Ontario

THE REPORT OF THE

Royal Commission on Electric Power Planning

Chairman: Arthur Porter

VOLUME 4

Energy Supply and Technology for Ontario

Ontario

THE REPORT OF THE

Royal Commission on Electric Power Planning

Chairman: Arthur Porter

February 1980

Published by the Royal Commission on Electric Power Planning
Printed by J.C. Thatcher, Queen's Printer of Ontario

ISBN: The Report (9 volumes): 0-7743-4672-8
ISBN: Volume 4: 0-7743-4666-3

Design and production management: Ken Slater
Photocomposition: Shirley Berch
Text management and photocomposition facilities: Alphatext Limited

Graphics: Acorn Technical Art

Editors: T.C. Fairley & Associates; R.A. Grundy & Associates

For the Commission: Ann Dyer, Editorial Coordinator; DebbieAnne Chown, Terminal Operator

Royal Commission on Electric Power Planning

ARTHUR PORTER, Chairman
ROBERT E. E. COSTELLO,* Commissioner
GEORGE A. McCAGUE, Commissioner
SOLANGE PLOURDE-GAGNON, Commissioner
WILLIAM W. STEVENSON, Commissioner

ANN DYER, Executive Programme Co-ordinator
FREDERICK R. HUME, Q.C., Legal Counsel
PETER G. MUELLER, Senior Advisor
ROBERT G. ROSEHART,† Scientific Counsellor
ROBERT A. SCOTT, Q.C.,‡ Legal Counsel
RONALD C. SMITH, Executive Director

*Resigned on 9 May 1977 due to ill health
†Resigned on 30 June 1977 to become Dean of University Schools, Lakehead University
‡Lost his life in the air crash on September 4, 1976

Previous publications of the Royal Commission on Electric Power Planning

Shaping the Future. The first report by the Royal Commission on Electric Power Planning. Toronto, 1976

The Meetings in the North. Toronto, 1977

Outreach Guidebook. Toronto, 1976

Issue Paper 1: Nuclear Power in Ontario. Toronto, 1976

Issue Paper 2: The Demand for Electrical Power. Toronto, 1976

Issue Paper 3: Conventional and Alternate Generation Technology. Toronto, 1977

Issue Paper 4: Transmission and Distribution. Toronto, 1977

Issue Paper 5: Land Use. Toronto, 1977

Issue Paper 6: Financial and Economic Factors. Toronto, 1977

Issue Paper 7: The Total Electric Power System. Toronto, 1977

Issue Paper 8: The Decision-Making Framework and Public Participation. Toronto, 1977

Issue Paper 9: An Overview of the Major Issues. Toronto, 1977

A Race Against Time: Interim Report on Nuclear Power in Ontario. Toronto, 1978

Our Energy Options. Toronto, 1978

Report on the Need for Additional Bulk Power Facilities in Southwestern Ontario. Toronto, 1979

Report on the Need for Additional Bulk Power Facilities in Eastern Ontario. Toronto, 1979

List of Volumes

The Report of the Royal Commission on Electric Power Planning is comprised of the following volumes:

Volume 1: Concepts, Conclusions, and Recommendations

Volume 2: The Electric Power System in Ontario

Volume 3: Factors Affecting the Demand for Electricity in Ontario

Volume 4: Energy Supply and Technology for Ontario

Volume 5: Economic Considerations in the Planning of Electric Power in Ontario

Volume 6: Environmental and Health Implications of Electric Energy in Ontario

Volume 7: The Socio-Economic and Land-Use Impacts of Electric Power in Ontario

Volume 8: Decision-Making, Regulation, and Public Participation: A Framework for Electric Power Planning in Ontario for the 1980s

Volume 9: A Bibliography to the Report

VOLUME 4

Energy Supply and Technology for Ontario

Richard Jennings, John Neate

The Authors

RICHARD JENNINGS graduated from the University of Toronto with a degree in industrial engineering in 1977 and subsequently obtained an M.B.A. degree. He began working for the Commission in May 1977 in the areas of energy supply technology and energy demand. He remained in that capacity until September 1979, when he took up the position of scientific research officer at the Ontario legislature.

JOHN NEATE graduated from McGill University in 1972 and subsequently obtained an M.A. degree in environmental studies from York University. He began working with the Commission in January 1976, assuming a number of responsibilities. Mr. Neate is currently involved in a number of energy planning projects.

Authors' Acknowledgements

The authors would like to extend their sincere appreciation to all who assisted in the production of this volume, and in particular to Gordon Patterson, Gail Randall, Fred Schwartz, and Ian Connerty.

Table of Contents

good

Foreword

The Commission wishes to acknowledge the contributions to our Report made by the authors of this volume. The enormity of the task as well as the skill and tenacity with which it was performed are testimony to the talents of Richard Jennings and John Neate. Our work would have been immeasurably more difficult without their assistance.

This volume, *Energy Supply and Technology for Ontario* focuses on a key issue area raised by the public during the Commission's public hearings process. The analysis, conclusions, and recommendations reflect data received by the Commission in the form of public testimony and exhibits, consultants' reports, and independent research and analysis by the authors. We have relied heavily on this work in formulating our own conclusions and recommendations in Volume 1. However, the views expressed in this volume are ultimately the responsibility of the authors. This document is therefore best viewed as a background paper which attempts to draw together the detailed evidence and analysis available on this complex subject, in a fashion which will be of use to the general public as well as to the technical community.

The research and evolution of this document were directed and reviewed for the Commission by Philip A. Lapp and Peter G. Mueller.

Arthur Porter, Chairman.

Executive Summary

The energy situation is of critical concern to Ontarians. Considering the uncertainty about the continuing availability of energy supplies, it is apparent that new structures, attitudes, and techniques are fundamental to the development of a more energy-efficient society. For Ontario, a long-range energy plan based on the diversification of energy-supply sources should receive priority. The lead times for the development of alternative options are long, and planning should be started now for technologies that may not have a significant impact on the total energy supply situation until well into the next century.

Electric power generation in Ontario has grown from an almost exclusively hydraulic programme, using a renewable resource, into a programme that is more than half thermal and thus heavily dependent on non-renewable resources. The growth in the demand for electricity is a reflection of the convenience of this form of energy in meeting many of the requirements of a highly automated society. In addition, the use of electricity has grown for space heating and water heating – the former being a seasonal load on the power supply system. Generating capacity requires large amounts of capital investment so seasonal loads are not particularly attractive for the utility to supply, particularly considering the thermodynamic losses that are inherent in converting electricity into thermal energy. Energy storage technologies may reduce this imbalance (both seasonal and daily), but not without a higher capital cost.

There is no doubt that Canada is fortunate in having a number of energy opportunities. Current trends are towards the continuing development of all economic sources of oil and natural gas, including exploration in the frontier regions. However, it must be recognized that other energy prospects, such as coal, nuclear, hydraulic, solar, and biomass resources, require further development. This will certainly require a co-ordinated effort by industry and government. Table 3.11 in Chapter 3 summarizes the status of the energy options of major importance to Ontario, with emphasis on electric power generation.

There are a number of energy storage technologies that could alter the patterns of energy use in Ontario. Electrification of a larger portion of the transportation sector is a distinct possibility, particularly in the light of recent developments in battery storage technology. It will require planning at the utility level to ensure that sufficent generating capacity is available to meet this new demand. However, it is unlikely that the extent of this demand will be significant before the year 2000, and it could be managed by the use of off-peak electricity. Assuming 500,000 electrical cars in Ontario by the year 2000, for example, only 600 MW of off-peak electric power capacity would be required for charging. Thermal energy storage systems charged by electricity have similar potential to use off-peak power. Thermal storage is integral to most solar-heating system designs, and it is possible that off-peak electrical heating units controlled by the utility could become an auxiliary option in some situations. However, it is unlikely that new generating capacity will be required to meet this demand. Combined fuel-cell electrolysis systems could reduce the off-peak electric power losses that might result from an expanding nuclear base-load programme coupled with lower rates of growth in the demand for electricity. The development of this energy storage option would be dependent on the availability of inexpensive off-peak electricity. Pumped-storage schemes, operated by the utility largely to control daily load variations, have limited potential in Ontario due to the lack of suitable sites. The Delphi Point scheme could provide up to 2,000 MW of storage, but land approvals might be difficult to obtain.

The development of technologies that improve the efficiency of energy utilization should receive priority in Ontario. Co-generation is an important option, particularly where wood or municipal wastes can be used as a fuel. In addition, where an industrial process-steam market exists, co-generation can provide an attractive alternative to conventional utility-operated thermal generating stations. The extent of Ontario's co-generation potential will be determined largely by relative fuel prices. Up to 3,000 MW of co-generation could conceivably be installed between 1980 and 2000. District heating schemes can also greatly improve the efficiency of energy use but require considerable capital expenditure, especially where community infrastructures already exist. There are, however, other low-grade heat markets, such as greenhouses and aquaculture, which should be considered when new thermal generation facilities are being planned. Like energy storage, load-management devices are particularly attractive when high-capital-cost/low-operating-cost base-load capacity in the electric power system is being operated at low capacity factors, as could be the case in the Ontario Hydro system by 1987.

Conservation is perhaps the most economic energy-related investment that Ontario can make. For example, increasing the insulation levels in housing to save a unit of energy is less expensive than building new energy production facilities to create a unit of energy. Assuming implementation of the insulation levels contained in the National Research Council's Measures for Energy Conservation in New Buildings, even with a 1.5 million (37.5 per cent) increase in the number of Ontario dwellings between 1975 and 2000, the additional energy requirement would only be 40,000 terajoules, representing a 9 per cent increase in energy consumption.

In the commercial sector, the development of more energy-efficient designs for building could result in considerable savings. Where both heating and cooling is required, especially in large commercial buildings, the use of heat pumps could cut energy consumption by 50 per cent. Overall growth of energy consumption in this sector could range from 0.5 per cent to 1.4 per cent per year, depending on the extent to which energy conservation measures are implemented in new commercial buildings.

In the industrial sector, as energy costs continue to climb, the use of energy conserving equipment and production methods will increase. Waste heat recovery, the use of continuous processes, and the use of smaller motors at higher loads would save significant amounts of energy. The annual growth rate of industrial energy consumption could be reduced from an estimated 3.4 per cent to 2.2 per cent if energy conservation measures were implemented. Efficiency improvements such as smaller cars and greater use of public transit will most likely limit any increase in Ontario's transportation energy requirements, even with a doubling of activity.

Natural gas will probably remain the major fuel used for home heating in Ontario largely because of its lower cost. It is conceivable that, by the year 2000, 75 per cent of Ontario's households will be gas heated, especially with improvements in gas furnace efficiencies and in insulation levels. It is unlikely that electricity will replace gas for direct-heat applications, except perhaps for a few specialized industrial applications. Coal will probably be used increasingly to raise process-steam, particularly as fluidized bed combustion technology becomes available. Electricity is much too expensive for this application. Electrification of a portion of Ontario's transportation represents the most significant new market for electricity in this province. Electrical cars are more energy-efficient than conventional vehicles, and their use would significantly reduce fossil-fuel consumption. Even greater savings may be achieved by increasing the role of electrified public transit in relation to other modes of transportation.

With the considerable uncertainties that are inherent in the supply and utilization of conventional fuels, increased use of renewable energy forms and implementation of more efficient energy-utilization technologies appear to be fundamental to the development of a viable energy strategy for Ontario. However, the shift from an energy economy based on exhaustible supplies to one based on sustainable and renewable energy sources will be gradual and will only become widespread as the existing energy infrastructure is replaced in the course of the natural wearing-out of capital equipment.

Over the next two decades the emergence of improved conversion and utilization technologies for conventional fuels and the implementation of energy conservation measures will tend to reduce the overall energy growth rate in Ontario. This could affect electricity load-growth rates in a number of ways, complicating the planning of additional electric power generating facilities. For example, at higher rates of growth in electricity demand, in the order of 3.5 per cent per annum and greater, nuclear base-load capacity for electric power generation appears to be inevitable, while at lower electricity demand growth rates alternative generating technologies become a more attractive possibility.

Below a certain level, in the range of 2.5 per cent per annum load growth, no further base-load capacity is required until beyond the year 2000. Unless massive penetration of electrical resistance space, water, and process heat occurs, which is unlikely, the electricity growth rate in Ontario will probably not exceed an average of 3.0 per cent per annum to the year 2000. At this level, only 1,500 MW of new base-load capacity will be required, and this could be met by co-generation or through interconnections with other provinces. Beyond the year 2000, the number of energy options available to Ontario should be much greater. However, the availability of these options is dependent on the extent to which the province undertakes research and development over the next 20 years.

CHAPTER ONE

Introduction

The Scope of This Volume

The purpose of this volume is to present an overview of the energy-supply options available to Ontario and of possible improvements in the efficiency of both the supply and the utilization of this energy.

The first chapter discusses the overall constraints affecting energy supply and touches briefly on aspects of the energy problem that are of particular relevance to the broader questions of societal trends. Questions are raised concerning the future growth of the demand for electricity, new markets that may arise, creating new demands, and control technologies that may intervene to reduce the demand or mitigate potentially hazardous impacts.

Chapter 2 traces the history of electric power development in the province and considers briefly how utility operation influences fuel-supply requirements.

Chapter 3 explores the range of energy supply resources that are of major importance to electric power generation in Ontario. The availability of supply and conversion technologies and the status of related research and development programmes are emphasized.

Chapter 4 explores the range of energy storage technologies that could be implemented to maximize the efficient utilization of existing energy resources. The assumption is made that energy storage is one way of maximizing the benefits from generating stations now in operation, where the majority of capital expenditures and social risks have already been incurred.

Chapter 5 reviews a number of current and emerging technologies that offer potential for improving the efficiency of the electric power system. Co-generation, district heating, and load-management are all discussed.

Chapter 6 focuses on energy conservation, examining some of the recent initiatives that have been undertaken in the various sectors and speculating on how some of these measures may affect electricity requirements. Improved household insulation standards, more efficient urban transit, improved building design in the commercial sector, and efficiency improvements in the industrial sector are all discussed.

Chapter 7 explores the question of inter-fuel substitution. It considers how and in what sectors alternative sources are likely to be substituted for forms of energy supply that are being used at present.

The final chapter presents a number of possible energy growth scenarios for the province and suggests how the growth in energy demand might be met. Emphasis is placed on the range of generating technologies that could be used to meet future electricity generating requirements. The chapter outlines some of the criteria that should be taken into account in developing an energy strategy for the province.

Ontario within the Broader Setting

The flow of energy within a society is a fundamental process that allows its communities and industries to function and provides it with goods and services. In 1978, Canada consumed 9.4×10^{18} J (9 quads)[1] of primary energy, which represents the highest consumption of energy relative to economic output of any western industrial nation. Ontario accounts for approximately 38 per cent of Canada's total energy consumption. The province imports 80 per cent of its primary energy from other provinces or from abroad in the form of oil, natural gas, and coal. Its indigenous resources are hydraulic energy, uranium, a limited amount of lignite, biomass, wind, and solar energy. In the past, the demand for energy has been closely related to economic growth in the province and Ontario's pre-eminent industrial and economic position has depended heavily on the availability of abundant energy supplies, made possible in part by the development of a vast electric power system.

The most important form of energy used in Ontario is oil. Partly as a result of the OPEC oil embargo of 1973 and the sharp increase in the price of world oil, Canada has been experiencing major uncertainties concerning the availability of what was once considered inexpensive energy. In 1974, the National Energy Board predicted that Canada would run short of domestic oil in the early 1980s. However, although Canada is at present a net importer of crude oil, recent discoveries, and the domestic heavy oil

and tar sands potential, suggest that this situation may change – but not without significant increases in the price of oil. It is inevitable that Canadians will have to pay a premium price for domestic tar sands oil, in order to support the costly extraction process. At an estimated minimum cost of $3 billion, however, a tar sands plant in Alberta may not be a very attractive investment for Ontario consumers, in comparison with other options, such as reducing our demand for oil. Nevertheless it has been suggested that recent oil finds could result in approximately 300-500 million m^3 (or approximately 2,000-3,200 million barrels)[2] of additional oil production, if advanced recovery techniques are used, which in turn could reduce the pressure to develop expensive tar sands and other related heavy oil deposits. Established remaining and recoverable reserves of conventional oil are about 1 billion m^3, or 10 times Canada's present annual domestic consumption.

National Energy Board estimates of established Canadian gas reserves are larger, totalling about 1,900 km^3 (67 trillion cubic feet), or enough for about 25 or 30 years of production at current rates. However, most of the energy infrastructure in eastern Canada is geared to the use of oil, particularly with the availability of low-cost heavy oil produced from under-utilized eastern refineries. Unless Canada can convert a significant number of oil-users in eastern Canada to natural gas, the prospect of a major oil shortage for the east continues to face Canada. Recent natural gas finds off the east coast, near Sable Island, could be as high as 5 trillion cubic feet (tcf) and could provide eastern Canada with an alternate supply, though there would be large infrastructure requirements such as pipelines and storage facilities. Even under the best of circumstances, that is to say, even with relatively abundant supplies of oil and natural gas, Canada will need all the time, determination, and money it can get to develop alternatives to these non-renewable energy resources. For Ontario, the situation is equally critical, considering the province's dependence on energy imports.

Conservation strategies emphasize reducing the rate of increase in energy demand, rather than attempting to expand the supply of conventional energy forms. The real significance of effective conservation for Ontario is that it could provide the time needed to develop alternative energy options so that the province could make the most appropriate and economic long-term energy decisions. At its most superficial level, conservation involves greater energy consciousness without significant life-style changes as the substitution of more energy-efficient equipment takes place. Putting out unnecessary lights, driving more slowly, using less hot water, and engaging in fewer energy-intensive activities are a few examples of energy conservation measures that we can all practise. However, it is uncertain to what extent voluntary conservation will affect the demand for energy . As we move forward in time, and as equipment and buildings require replacement, versions that use less energy can be substituted. Capital invested in such schemes can be offset by the dollars that would otherwise have been spent on additional expensive energy supplies. Beyond this, significant changes in urban planning and transportation in the long term could have a profound effect.

Canadians now require about 75 per cent more energy per unit of economic output than a number of other western industrial nations (e.g. Sweden, West Germany, Japan).[3] This is partly because cheap energy was available in the past, and partly because of our cold climate and extensive transportation requirements. It has been suggested that, as conservation measures are implemented, Canada's energy-intensity, or the amount of energy we need to produce a unit of economic output, will decrease.[4] Although climatic and geographic factors will continue to demand high energy inputs for Canada, with a shift towards greater energy-efficiency there may be a tendency for energy use and economic growth to become separated in the decades ahead. Furthermore, since continued exponential growth in energy use, even if it were sustainable, does not necessarily lead to exponential increases in net human well-being, it is reasonable to conclude that there may be advantages in developing active strategies to separate energy growth from economic growth in an orderly and controlled manner.

Another incentive for the development of alternative economic and energy strategies is the possibility of saturation in the consumption of some goods and services, which may ultimately lead to a situation in which traditional industrial production can no longer be expanded at historical growth rates. This will probably reduce the future rate of growth of energy demand. In the future, as Canada is confronted with the important task of refitting technology to meet conservation and environmental goals, the provision of goods and services will most likely be characterized by significant improvements in design- and energy-efficiency. However, while energy conservation efforts such as these can be effective, they will need from government both an ongoing commitment and effective co-ordination.

For Ontario, without an obvious single solution to its energy problems, a long-range plan based on the

diversification of its energy resources should receive priority. As energy resources become more expensive and increasingly difficult to obtain, new energy supply options should be developed, where opportunities exist, in a way that is closely integrated with growth in the various types of energy utilization activity. Matching the form of energy supply to specific end-use applications could reduce many of the inefficiencies inherent in our present energy delivery system.

Issues and Concerns Raised before the RCEPP

During the Commission's hearings, many submissions were made by the public, industry, government, and Ontario Hydro regarding the range of electricity and energy supply options available to the province. To optimize the use of non-renewable fuels, many advocated the development of co-generation possibilities. This process, as the name suggests, involves the use of both the electricity and the heat energy, usually in the form of steam, that are produced during the thermal generation cycle. The heat energy can be used for steam requirements in industry or for district heating. During the presentation by Dow Chemical of Canada Limited, it was suggested that:

> If Ontario Hydro, using their background and their capability, were to move into an industrial area with a community surrounding that industrial area . . . they could utilize the district heating concept and steam-supply concept very effectively.[5]

Widespread application of co-generation would result in a much more decentralized electricity generation system than at present, and would greatly increase the efficiency of fossil-fuel utilization.

Other decentralized electricity generation technologies were also advocated. In a presentation by Barber Hydraulic Turbine Ltd. concerning the development of Ontario's small-scale hydraulic potential, it was suggested that:

> . . . it [is] timely now to assist the [electric power] system by refurbishing . . . smaller plants and develop[ing] some additional ones. Old outputs will be increased by subsequently improved technology and in aggregate they will provide a useful if small contribution to the regional energy plan . . . [the] old existing dams in many cases must be maintained for local environmental reasons in any event. One should thus use the available potential power to generate electricity. A programme of rehabilitation coupled with augmentation of output at a number of selected small sites will provide a variety of work in each locality and a continuing energy advantage from the renewable resource of current solar energy.[6]

Perhaps the best way to take advantage of renewable solar energy is through the use of wood. As suggested in a submission by the federal Department of Fisheries and Environment Canada, significant potential exists in the utilization of wood to meet a portion of Ontario's energy requirements:

> In Ontario, 198,636,000 acres (79,454,400 hectares) of land are classified as forested. Of this, 60,703,000 acres (24,281,200 hectares) are available for the production of forest products. If an intensive energy forest programme were initiated, it is reasonable to assume that 6,070,300 acres (2,428,120 hectares), or 10 per cent of this land, could provide enough biomass for approximately 10,000 MW of installed generating capacity, or 4 billion gallons of methanol.[7]

Further discussion of solar energy included the potential of direct solar utilization to meet certain heating requirements, thereby reducing the need for conventional fuels or electricity for space-heating applications. A submission from a resident of Thunder Bay advocating solar heating stated:

> Solar can work very simply, very efficiently. I say the solar panels that I have, the water panels, the whole system is costing under $10 a square foot. Okay, if it costs me $6,000, fine, I will get my money back in less than 15 years the way prices are escalating.[8]

Furthermore, Professor Frank Hooper of the University of Toronto suggested:

> Solar energy for space heating is . . . already essentially competitive with fossil-fuel systems.[9]

Many of the submissions dealing with both coal and nuclear technology focused on the environmental, health, and safety factors. On the question of environmental control technology for coal combustion the Minnesota Pollution Control Agency stated:

> Under current federal policies, the United States Environmental Protection Agency considers sulphur dioxide scrubbing systems to be the best available control technology for large fossil fuelled electric generating plants. As a result, scrubbers are, at this time, required on any such new facilities in Minnesota. The major benefits of using these systems are reduced sulphur dioxide emissions and therefore reduced air quality impacts on surrounding areas. In addition, removal of significant amounts of sulphur dioxide will reduce the potential for acid rain.[10]

In support of coal-fired generation to meet the bulk of Ontario's future electricity requirements, the Ontario People's Energy Network (OPEN) suggested:

> ... the technology does exist to make coal clean. It may be expensive but it may also get cheaper in time. The problems of coal are problems that we have a great deal of experience living with, if nothing better than that. There are quite a number of problems associated with nuclear ... for which [even expensive solutions] do not exist.[11]

However, it should be noted that large-scale development of coal-fired generation could lead to massive escalation of atmospheric carbon dioxide and acid rain. The case in favour of nuclear power was clearly stated by William Morison of Ontario Hydro:

> We don't have any fossil fuels [in Ontario]; we are running out of hydraulic power; [and] we feel the solar and wind sources are probably below the North American average. What do we have? Well, we have large quantities of nuclear fuel both in Ontario and Canada, very substantial quantities just contracted for, and hopefully more in the future. We have expertise in mining and ore processing and facilities and experience to carry that on. In fact, there is in Canada, mostly in Ontario, the installed capability to support 40,000 electrical megawatts at the present time in the mining area. Most of that is being exported. We have large cool bodies of water, particularly the Great Lakes system, which are essential for efficient conversion of thermal energy ... to electricity. We have excellent research and development facilities in this field, we have design and construction and project management experience, both in Ontario Hydro and in industry and in AECL.[12]

Morison then commented:

> Is there any doubt that nuclear power is appropriate technology for Ontario? We have integrated competence from research right through to operating and we can use that to expand the generating facilities to meet the future needs, whatever they really are.[13]

However, on the basis of many of the submissions received by the Commission, there appear to be some reasons for doubt. Critics argue that long-term radioactive wastes left to future generations, the risks of catastrophic nuclear accidents, commercial nuclear power's contribution to nuclear weapons proliferation, and the need for elaborate security arrangements are aspects of nuclear power that have important moral implications. This was emphasized in the summary argument presented by Gordon Edwards and Ralph Torrie:

> Nuclear power seems to be a technology which is lacking an appropriate context. It demands a peaceful world, but the world is not as peaceful as we might like. It demands a highly centralized society, subjected to various types of controls, which many people do not desire. It demands a degree of vigilance which is unparalleled, a degree of dedication which is unprecedented, a degree of planning which is unheard of, and a degree of security which is little more than an ambitious hope. Such a technology will inevitably attempt to create the environment which it demands, and in so doing it will have far-reaching implications on all our lives.[14]

Regardless of the source of power generation, most of the participants seemed to agree on the need for improvements in energy-efficiency.

The RCEPP issue paper entitled *Conventional and Alternate Generation Technology* highlights a number of these issues. Both energy conversion and energy storage are discussed in the paper, with special attention to the potential for greater process efficiency. As the paper suggests, whenever the process of energy conversion takes place, there is an inevitable degradation in the quality of some of the energy. What this really means is that it is impossible to convert all the energy in a given quantity of fuel entirely into work. The conversion of fuel to electricity is very inefficient. Large amounts of heat, often in the order of 60 to 70 per cent of the total energy potential in the fuel, are lost in the conversion process.

The overall capacity of the electric power system can be increased by storing energy during off-peak periods, that is, at times when the demand for electricity is low. The most widely used method of carrying out this process is "pumped storage". Water can be pumped from one point to a higher point by using electricity-powered pumps. The water that is then stored in an elevated reservoir can be released when required, and the force of gravity can be used to provide energy to generate electric power. Ontario Hydro's pumped-storage scheme at Niagara is an example of this process. Another way of storing electric energy is in the form of hydrogen gas, produced by the electrolysis of water. This is the opposite process to the one that forms the basis for the fuel-cell energy storage and conversion systems. On a smaller scale, electricity can be stored in batteries; the manufacture of efficient, inexpensive, light-weight batteries could result in a shift to electricity-powered automobiles and small trucks.

The upgrading of energy-efficiency through improved energy conversion cycles and through the use of energy storage systems is an important aspect of energy planning that must be considered by energy utilities and energy users.

A thorough examination of these conversion and storage technologies will be presented later in this volume. Some of the methods of utilizing waste heat, including heat exchangers, heat pumps, and district heating, will also be discussed. The technology for storing thermal energy, such as that made available by solar thermal collecting devices, will also be explained.

Constraints Affecting Energy Supply

The development of energy resources is limited by a number of factors, some of which are difficult to predict. It is not so much that energy is in short supply, as that the obstacles to the development of certain resources are numerous and difficult to overcome. The constraints affecting energy supply range from institutional to geographic, but the time constraint is perhaps the most difficult one.

In general, the production of a quantity of useful energy, such as a kilowatt hour of electricity, involves several dimensions of cost: the diversion of conventional materials and capital resources, all of which are normally reflected in the market price of energy; the consumption of a quantity of a fuel resource, thus in some cases precluding its use in the future; the degradation of natural and man-made structures and materials; the distribution of energy; the impact on human health and safety; and the impact on communities and their life-styles. A balanced and coherent view of the energy situation requires that costs and impacts throughout the entire fuel cycle be identified, quantified, and compared on a consistent basis. A comprehensive assessment of the factors affecting all forms of energy is desirable, but such a detailed study would be beyond the scope of this volume. However, it will be useful here to examine a number of key constraints in relation to Ontario's energy supply options.

Physical Constraints

Geographic and Transportation Factors. The physical environment plays a significant role in the supply of energy to Ontario. For example, the geography of the province and its many resources have contributed to the development of hydroelectric power and an extensive forestry industry. However, Ontario does not possess significant quantities of oil or natural gas, and its coal resources are limited to the Onakawana lignite deposits in the northern part of the province.

Because much of Ontario's industrial capacity depends on a supply of vast quantities of fossil fuels, transportation is a key factor. Furthermore, since most of the large hydroelectric sites in the southern part of the province have been exploited, development of further hydro power may require long transmission lines that will inevitably have social, environmental, and aesthetic impact.

Although the technology is now in place to permit the delivery of vast amounts of conventional energy resources, any significant shift, for example, towards heavy dependence on coal, would require an extensive transportation infrastructure, at significant cost. The lack of indigenous fossil-fuel resources places the province at a distinct disadvantage when one considers the cost of transporting these energy forms over great distances. On the other hand, uranium, which is available in significant quantities, provides the province with relatively low fuel costs, in addition to export potential. However, the capital investment required to construct nuclear power facilities is high, and the possibility of using uranium as a fuel for smaller-scale facilities, for example, in the order of 100 MW for co-generation applications, is economically uncertain.

Ontario also has thorium deposits, which are generally thought to be up to four times the size of the province's uranium deposits, although no detailed surveys have been made. Development of the thorium CANDU cycle would require an extensive capital and research commitment.

Climate. Climate has a significant influence on both energy supply and energy demand. Atmospheric processes associated with the sun determine the supply of renewable energy resources, as well as the extent to which carbon dioxide and air pollutants such as sulphur dioxide, produced by the combustion of fossil fuels, are dispersed into the atmosphere. With a variable and often very cold climate, Ontarians expend a lot of energy simply to cope with weather. For example, the level of utilization of energy for space heating in a home or factory depends upon the amount of heat loss across the building membrane, which increases as the outdoor temperature drops and wind velocities increase. Ontario Hydro's peak demands for electricity generally correspond to the coldest periods of the winter because of the increased heating requirements and the shorter periods of daylight.

Although renewable energy is often considered to be abundant, even inexhaustible, climate is a limiting factor. Solar systems, for example, tend to fall down when there are successive cloudy days. Estimates obtained from the Atmospheric Environment Service indicate that a run of 11 successive cloudy days during the winter in Toronto has occurred twice in the last 20 years.[15] It would appear that the design of solar-heating systems in Ontario should incorporate an auxiliary fuel device, and/or an adequate energy-storage device, for use at such times. If electric resistance space heating is used as the auxiliary system, the utility is still faced with the problem of servicing the same peak demands corresponding to cold spells and periods of low illumination. However, these peak demands could be reduced if electricity were used, instead, to charge thermal storage devices during off-peak periods.

Perhaps of greatest concern to climatologists is the impact that man's activities, particularly those involving the combustion of fossil fuels, are having on the physical atmosphere. The addition of carbon dioxide to the atmosphere over the next century could contribute to a general warming of global climate; this is known as the greenhouse effect, whereby the presence of higher concentrations of carbon dioxide will increase the ability of the atmosphere to absorb infrared radiation emitted by the earth. It has been suggested that, with an increase in global temperature of only 1° Celsius, glaciers would begin to melt, causing a rise in sea level. Semi-arid areas, such as the Prairies, could be made unsuitable for agricultural uses. However, it is not entirely clear whether the greenhouse effect will melt down the icecaps or build them up through increased precipitation. This controversial issue is discussed in some detail in Volume 6 of this Report.

Population. The number and distribution of people living in Ontario is obviously a key factor in determining the future requirements for energy supply. Most recent forecasts suggest that Ontario's population will be approximately 10.1 million by the year 2000.[16] This represents a reduction in the expected population growth rate to 0.8 per cent per annum from the previous forecast of 1.4 per cent per annum. The reduction in population growth rate will have a considerable effect on the number of new residential building construction starts in the province, which in turn will affect energy consumption. It is possible that by 1985 a large proportion of Ontario's housing requirements to the year 2000 will already be in place, an inevitability associated with the baby boom of 1945 to 1960 and the ensuing strong demand for housing, which is now expected to decline gradually.[17] These and other issues are discussed in Volume 3 of this Report.

Socio-Economic Constraints

Beyond the purely physical parameters, the development of energy supply and technology is affected by a set of socio-economic constraints largely determined by institutional, economic, and political factors. These must be placed in perspective in order to understand the options confronting the province of Ontario.

Centralization and Decentralization. The energy requirements of a large city are vastly different from those in a rural area. In the city, vast amounts of energy are consumed every day in the transportation sector as well as by the many industries and homes that comprise the urban environment. In rural areas, spatial factors present a different set of problems. Lower population densities and the fact that goods and services must often be transported over great distances add to the cost of each unit of energy. Although the presence of an industrial manufacturing, resource recovery, or agricultural operation can place a significant demand on the energy supply system, energy options are often available to these processes. For example, pulp and paper and sawmill operations are often close to hinterland forest resource areas, and agriculture usually has available to it significant quantities of organic waste that can be converted into methane; agriculture can also make use of solar energy for certain drying operations. The dilemma emerges that, while the city has a more concentrated population and hence a greater potential both to market energy efficiently and to conserve it, rural and hinterland areas are closer to a number of alternative energy options. Because of the diffused pattern of energy utilization in the countryside, these options may involve higher costs, at least at the outset.

The most fundamental problem pertaining to energy utilization within the urban context is the existence of a huge infrastructure that cannot easily be changed. Many of our buildings, industries, and transportation systems are inefficient. In some cases, improvements can readily be achieved; beyond a certain point, however, energy improvements will take much longer to bring about. For example, a district heating distribution system within a built-up urban core will require vast energy expenditures to install and operate. Furthermore, when new office buildings are constructed with energy-conserving systems that have already been demonstrated,[18] the long-term benefits of a district heating system

may be insignificant. Efforts to curtail energy use at the point of utilization is perhaps a more likely scenario, when one considers the cost of changing energy supply systems. However, the shift towards a range of alternative energy supply systems, where the potential exists, is still the key to a more resilient energy system for Ontario. For example, the planning and development of new subdivisions and industrial parks should take into account opportunities for increasing energy efficiency. A reduction of energy consumption for transportation has perhaps the greatest potential within the urban context. Greater use of public transit and less dependence on the automobile would reduce energy consumption within urban areas by a substantial amount.

Rural and northern Ontario may be generally described as agricultural and resource-producing areas; they also include regions that are designated as native and recreational land. The spectrum of energy supply and utilization in these areas is wide. The sense of being locked into certain energy patterns is not as great as it is in urban areas, with the notable exception of transportation.

The agricultural community has been especially active throughout the Commission's deliberations. There is a recognition that energy plays a key role in modern agriculture, but that certain measures can be instituted to promote energy conservation and self-sufficiency. There is no question that the electrification of rural Ontario has had a significant impact on the ability of farmers to produce at higher yields through increased automation. But the shift towards greater mechanization and its implied dependence on energy has created new problems for the agricultural community as a whole. It has been stated that the presence of significant amounts of air pollution from fossil-fuelled generating stations and industrial processes poses a severe threat to the viability of adjacent agricultural regions.[19] But there are a number of energy options that are technically viable depending on the specific characteristics of the particular end-use requirement. Some of these include: the use of solar energy for drying processes; the use of methane derived from organic wastes to fuel heaters; the use of methanol to drive farm machinery; and, in the case of land in the vicinity of the Bruce Generating Station, the use of waste heat from moderator water to heat greenhouses for year-round production and to provide heat for drying. In addition, small-scale hydraulic power and wind energy may be available in certain regions, while improved utilization technologies, such as the heat pump, may be applicable as well.

The resource extraction industries, which include mining and forestry operations, consume a high proportion of industry's total energy. The pulp and paper industry, perhaps more than any other industry, has the potential to become energy self-sufficient. The availability of large amounts of both mill and forest residue makes wood energy an attractive option in some instances. This has already been demonstrated in a number of situations across Canada.[20] The use of wood energy for the generation of both electricity and heat, most often referred to as co-generation, offers greater efficiency in the energy conversion process. This same approach can be applied to certain mining operations, where both process-steam and electricity are required. The delivery of the appropriate fuel for co-generation, most likely coal, should not present a problem because most of these extraction processes are already dependent upon a transportation infrastructure to convey their products to market.

In the past, the energy requirements of the more remote communities have been met by very costly shipments of diesel fuel. This arrangement is somewhat impractical, particularly with rising oil prices. The potential for developing hydraulic, wind, and wood energy in these more remote regions merits consideration. Ontario Hydro, in collaboration with the federal government and Treaty No. 9 Indians, is trying to assess the potential for small-scale hydraulic generation in remote areas. Similarly, the Ontario Ministry of Energy is exploring ways of utilizing wind energy in communities with wind régimes of sufficient magnitude. For larger communities, wood energy and energy derived from other sources of biomass, such as peat, may play an important role for electricity generation in addition to its current use for heating purposes.

The Cost of Energy. The real cost of energy to society involves a range of factors both internal and external to the production process.

Decisions about the relative competitiveness of various energy sources are often confused by the range of energy-accounting methods that can be used. It is now generally accepted that, where possible, energy costs should include the full range of costs over the entire fuel cycle. But these costs may be difficult to predict, particularly where the fuel supply is not indigenous to the province. Furthermore, even where an indigenous fuel supply does exist, certain future costs to the Province that may result from either the extraction or the utilization of the fuel may be equally difficult to quantify. This has, in the past, tended to bring about a number of generalizations regarding the cost of energy. Energy planners have only recently begun to analyse the cost of energy from the point of view of end use.

In view of the many uncertainties surrounding energy forecasting, a unified costing methodology is obviously a desirable component of energy supply assessment. One such attempt has been made by the U.S. Department of Energy;[21] in Canada, the Science Council has initiated a programme designed to provide an ongoing assessment of energy supply and technology.[22] It has been suggested that the lack of a comprehensive policy regarding the analysis of energy costs, such as the cost of supplying more electric power generation versus the cost of saving an equivalent amount, has caused a delay in the evolution of a more definitive long-range energy plan. There are, of course, many important factors. For example, while it may be a better investment to conserve rather than produce a unit of conventional energy, if energy consumption levels are reduced significantly, then it becomes more difficult to justify the large-scale development of some emerging energy technologies, particularly in the near future. This issue is discussed in considerable detail in Volume 5 of this Report.

Institutional Inertia. Another constraint on the development of new energy supply options and their associated technologies is the time it takes to bring about institutional change. It is not unusual to expect institutional support for existing technologies and patterns of development, for the simple reason that they are well established. Institutional change, whether in government, business, industry, or education, brings with it certain costs – economic, political, and social.

A shift in Ontario's energy strategy towards the development of a renewable energy scenario, for example, would require significant changes. Employment would be affected, particularly in the short term, as manpower adjusted itself to the new industrial requirements. New skills would be required, placing a heavy demand on community colleges and on-the-job training programmes. However, the tendency to support established interests and the time lag associated with most institutional changes are barriers to the introduction of new programmes. It is often difficult to institute changes that may result in disruptions of the status quo, regardless of how rational or necessary these changes may be.

The Time Constraint

A great deal has been said about the global energy situation since the OPEC oil embargo of 1973. In Canada, the recurring themes of commentators are conservation, energy self-sufficiency through an expanding development of domestic oil and natural gas resources, and, farther into the future, wide-scale development of renewable energy forms. Related to this is the recognition that many of Ontario's energy decisions have already been made – in fact, much of our energy infrastructure for the next two decades is already in place. Therefore, a major concern of energy planners is how to improve the efficiency of energy end-use patterns. Some analysts argue that the price of conventional energy will bring about these improvements as market forces take their course. Others, however, suggest that longer-term programmes must be implemented now in order to sustain the long-term energy supply. It is reasonable to assume that some conventional non-renewable energy forms will eventually be exhausted or will become prohibitively expensive. Efforts to conserve energy and develop renewable energy forms can only enhance Ontario's energy position in the long run. However, these efforts must be viewed in the proper time frame. The current situation with respect to solar energy is a useful illustration. Solar space heating and water heating, as we know them, are not new; in the 1950s a number of design competitions were held to promote domestic solar energy systems.[23] However, at the same time, the oil resource system was becoming increasingly widespread and, with an abundant supply, was very inexpensive.[24] This tended to discourage any widespread development of solar sources, largely because the high front-end capital cost of solar could not be justified, in comparison with the low capital and fuel costs of the oil-heating option.

However, solar energy appears to have a long-range potential as a source of both heat and electricity. The development of solar photovoltaic cells that can convert sunlight directly into electricity with heat as a by-product is still awaiting a major scientific breakthrough in materials research and cost reduction in order to justify large scale application. As with most new technological innovations, achievements in the photovoltaic area will nevertheless depend on programmes initiated now. Since significant lead times are required to implement new technologies, planning must be undertaken now, even though a particular technology may not have a significant impact on total energy supply until well into the next century. Although economic factors must play a key role in determining which alternative technologies ultimately receive priority, research and development programmes in all areas that appear promising should be seen as measures to ensure the availability of future options in an era of uncertainty.

Summary

The energy situation is indeed of critical concern to Ontarians. With considerable uncertainty about the future availability of supplies of energy, it is rapidly becoming apparent that new structures, attitudes, and ways of doing things are fundamental to the development of a more energy-efficient society. In Ontario, a long-range energy plan based on the diversification of energy supply options should have priority. With long lead times for the development of alternative options, planning must be undertaken now for technologies that may not have a significant impact on the total energy supply situation until well into the next century.

Electric Power Generation in Ontario

A History of Electric Power Development in Ontario [1]

During the 1890s, power was provided to some of the larger cities in Ontario by small thermal-electric plants, most of them privately owned. In 1895, the waters of the Niagara River were harnessed for electric power at Niagara Falls, New York. This was the first major hydroelectric station built in North America, introducing a new pattern of electric power development to the continent.

In the next two decades, numerous water-power leases were let to various private companies in Ontario. The major portion of Ontario's early hydroelectric power development was in the Niagara Falls area. For example, in 1898 the Cataract Power Company brought into operation the DeCew Falls Generating Station, which took its water supply from the nearby Welland Canal. The Canadian Niagara plant began operating in 1904, the Ontario Power Generating Station in 1905, and the Toronto Generating Station in 1906, all on the Niagara River.

In 1906, an act was passed, following a report by a committee of the Ontario Legislature, providing for the formation of the Hydro-Electric Power Commission of Ontario (hereafter referred to as Ontario Hydro) to deal with the supply of electric power to the municipalities.[2]

During early development, private enterprise continued to develop hydroelectric resources in various parts of the province. But between 1914 and 1922 Ontario Hydro acquired most of these plants and began to undertake developments of its own.

The largest development of the period was the building of the Queenston-Chippewa development to utilize power from the Niagara River. Now known as Sir Adam Beck-Niagara Generating Station No. 1, this plant first delivered power early in 1922. By the end of 1922, Ontario Hydro's generating resources totalled 496 MW and the total demand was 460 MW.

Ontario Hydro began a rapid expansion programme after World War II. Between 1945 and 1972, Hydro brought into service 41 new sources of power involving the generation of a total of 13,000 MW. As few large-scale accessible hydroelectric sites remained undeveloped, Ontario Hydro began to consider steam-powered generation. The first two coal-fired thermal electric stations went into service in 1951. The Richard L. Hearn Generating Station on the Toronto waterfront, and the J. Clark Keith station at Windsor today have a total combined capacity of 1,464 MW.

The next big construction projects were major hydroelectric developments at Niagara Falls and on the St. Lawrence River. The Sir Adam Beck-Niagara Generating Station No. 2, with an installed capacity of 1,400 MW, first generated power in April 1954. It consists of a 16-unit main powerhouse, with an associated pumped-storage system. The St. Lawrence Power Project was undertaken jointly with the Power Authority of the State of New York. Ontario Hydro's section of the power dam, the Robert H. Saunders-St. Lawrence Generating Station, produced its first power in July 1958. This project tapped the last major source of hydroelectric power in southern Ontario. During the ensuing years, Ontario Hydro set about developing most of the remaining small hydroelectric sites across the province, bringing 1,750 MW of hydraulic capacity into service between 1958 and 1971 at 18 locations on nine rivers.

The emphasis on thermal-electric generation increased steadily and by 1974 it represented approximately 63 per cent of Ontario Hydro's capacity. Lakeview Generating Station, a coal-fired station on the western outskirts of Metropolitan Toronto, delivered its first power in 1961. With the progressive addition of new generating units, it reached its full capacity of 2,400 MW in 1968. In 1963, the 100 MW coal-fired Thunder Bay Generating Station was commissioned. Hydro's fifth coal-fired station, the four-unit, 2,000 MW Lambton plant, on the St. Clair River 14 miles south of Sarnia, began producing electricity in 1969 and was fully operational in 1970. Construction started in 1968 on a 4,000 MW coal-burning plant at Nanticoke, a small Lake Erie community near Port Dover. By the fall of 1978, all eight 500 MW units were in service. In eastern Ontario, construction of Lennox Generating Station, 22 miles west of Kingston, started in 1970. Completed in 1977, this 2,295 MW plant is Hydro's first major oil-burning generating station.

Beginning in 1951, Ontario Hydro began to study the commercial use of nuclear power. In 1955, Hydro initiated its nuclear programme by signing an agreement with AECL and the Canadian General

Electric Company to design and build a small experimental nuclear station at Rolphton, Ontario. Known as the Nuclear Power Demonstration (NPD) Plant, it began feeding power into the provincial grid in 1962. In 1959, Hydro entered into an agreement under which AECL would build a prototype large-scale station. With a capacity of 200 MW, the Douglas Point Nuclear Power Station was constructed on the shore of Lake Huron, between Kincardine and Port Elgin. The station produced its first power in January 1967.

The next step in Ontario Hydro's nuclear programme, to construct a station of four 540 MW units at Pickering, east of Toronto, was announced in 1964. Pickering's initial performance was outstanding and the station was hailed as a major Canadian technological achievement. The first reactor started up in February 1971, just five and one-half years after construction began. It reached full output in three months, well ahead of schedule. Unit 2 reached full production in the fall of 1971, less than two months after start-up, and unit 3 surpassed both, moving from start-up to full power in less than three weeks. In May 1973, the fourth Pickering unit reached full power only 12 days after the reactor went critical. In 1968, Ontario Hydro announced plans to build a 3,200 MW nuclear station near the existing Douglas Point plant. It is called the Bruce A Generating Station, and the last of its four identical units came into service in January 1979. Beyond this, another 8,600 MW of nuclear capacity (Pickering B, Bruce B, and Darlington) is under construction or currently committed, and is scheduled to be in service by 1990.

Electricity Utility Operation

Given a forecast of electricity load growth that specifies a "most probable" firm load requirement in a particular year, an electric power utility attempts to choose an optimal mix of generating facilities to meet this demand. Although utility loads are affected by many variables – for example, industrial loads vary with the state of the economy, residential loads vary with the temperature, and street lighting loads vary with the season – the aggregate load fluctuates in a highly predictable pattern on a daily and seasonal basis.

For a typical utility such as Ontario Hydro, electric power loads on a weekday increase from a minimum during the early morning hours to a higher level in the forenoon and then to a daily peak in the late afternoon, after which they decrease slowly during early evening hours and rapidly in the late evening. During weekends and holidays, loads are usually at much lower levels throughout the day.

In order to meet the daily load requirements, a so-called "stacking order" of generating units is employed. At the bottom of the order, the generating stations (thermal or hydraulic) that are most efficient and least costly to operate are placed on what is termed "base-load" service, involving virtually continuous operation. During the off-peak, night-time hours, these base-load units may be able to provide electricity, in excess of what is needed immediately, that could be used to operate capacity storage units anywhere in the system. As the load builds up during the day, older or less efficient thermal and hydraulic units, usually with higher operating costs, are brought into service to meet intermediate-load requirements. During peak demand periods, various "peaking" hydro, thermal, and pumped-storage units are brought into use. As loads diminish, units are removed from service in the reverse order until the base-load situation prevails. The amount of generating capacity maintained on-line is at all times slightly in excess of the actual load, so that unpredictable short-term fluctuations in customer load can be accommodated. The difference between the actual load and the capacity on-line is termed the "regulating margin". It is normally relatively small, amounting to less than 2 per cent of the load of a large utility.

As previously mentioned, load also varies on an annual basis in a pattern that is reasonably predictable. Ontario Hydro, for example, has traditionally been a "winter-peaking" utility, with maximum demands in December and January. It must therefore plan to have sufficient capacity for these maximum demands either within its own system or by importing power. However, it can take advantage of seasonal variation by scheduling maintenance procedures at periods of lower demand, thereby maximizing the number of plants available at times of highest demand. If seasonal variation leaves capacity surplus to what is required for maintenance, there is the possibility of exporting electricity to other jurisdictions that may need it.

In addition to providing sufficient capacity for its maximum demands, the utility must allow for unforeseen occurrences that may affect its power system. These may include equipment failures, shutdowns, droughts, and storms. To provide instant generation should an eventuality of this nature occur, an additional amount of capacity, called "spinning reserve", is kept in readiness to accept load. Then, if

necessary, additional generation can be brought into service within a short time. These, together, comprise what is called a "generating reserve capacity" or "reserve margin".

Determination of the amount of reserve capacity needed involves a complex technical assessment of the probability of unexpected failure of mechanical and electrical components of the system (indicated by a calculation of "forced outage"[3] rates for the various generating units in the system) and the need to remove a plant from service for maintenance. Most major electricity utilities maintain detailed records of the operating status of their various generating units and can use this information to help produce a forecast of future planned maintenance and forced outage rates for similar classes of units. This helps to determine the amount of reserve capacity that should be planned for the future. A system that includes thermal (nuclear or fossil) units requires more reserve capacity than a hydroelectric system due to the higher forced outage rate and greater maintenance requirements of thermal generating stations. For example, to supply a load of 750 MW to the electric power system with acceptable reliability[4] from a number of thermal units may require an additional 1,500 to 2,000 MW of reserve capacity.

Constraints Specific to the Electric Power System

Conventional Costs

Conventional costs are definable costs that are embedded in the price of electricity to the consumer. These include capital costs as well as operating and maintenance costs for such things as fuel and labour. The availability of fuel at an acceptable cost is a major consideration in selecting the type of electric power plant to be built; for example, while natural gas may be more acceptable environmentally and the capital costs of a gas-fired station lower, coal or uranium may be more abundant, more accessible, or less expensive. The conventional costs of supplying electric power are also affected by the location of a power plant; for example, a facility that is close to a major load has the advantage of reduced transmission requirements. As with most large development projects, long lead times brought about, in part, by the regulatory process can increase the costs. In addition, interest and escalation costs are sensitive to time. Furthermore, a power plant whose design is technically mature, and which is therefore able to operate at a low forced outage rate, will tend to lower energy costs.

Environmental Costs

Environmental costs include those resulting from land, air, and water pollution, and the associated costs of controlling these impacts. The amount of land committed to power plants and their supporting fuel cycle is of particular concern in agricultural areas. The land component includes, for example, areas that are disturbed by mining or required for the disposal of waste materials.

The control of emissions of sulphur dioxide, nitrogen oxide, particulates, radioactive materials, and thermal waste from power plants can constitute a significant cost to society. The fossil-fuel energy system releases the greatest quantities of sulphur dioxide, nitrogen oxide, and particulates per unit of energy produced. Abatement costs include the cost of removing sulphur dioxide from flue gases and the reclamation of strip mine land. In the nuclear fuel cycle, radioactive waste disposal and the control of mine tailings are major problems.

Water pollution is of considerable concern in connection with both fossil and nuclear power plants, particularly at the front end of the fuel cycle. Examples of chemical contamination in the fossil-fuel system are acidic mine drainage in coalfields, black water from coal-cleaning and oil spills, and effluents from oil refineries. Concern about the nuclear fuel cycle is largely centred around the leaching of radioactive mine tailings. These matters are discussed in detail in Volume 6 of this Report.

Health Effects

The effects of electricity production on public health are extremely difficult to assess. The transport of a pollutant through various pathways to man is determined by a number of factors including meteorological and hydrological conditions, biological absorption mechanisms, and population distribution and life-styles. There are also hazards to the public resulting from conventional accidents in transporting fuels.

The dominant occupational health effect in the coal fuel cycle is black lung, or pneumonoconiosis, a respiratory disease resulting from the accumulation of coal dust in the lungs of underground miners.

This disease is often followed by progressive massive fibrosis. In the nuclear fuel cycle, lung cancer among uranium-miners due to inhalation of radon gas is a major concern.

Uncertainties

There are a number of uncertainties that may further complicate these costs. For example, with the market fluctuations that the Canadian dollar has experienced, the cost of U.S. or offshore capital is difficult to predict, as is the escalation of labour and material costs.

As power plants, and particularly, nuclear power plants, get older, the frequency of occupational and public hazards may increase, although it is possible that with an increase in operational experience, these potential hazards may be reduced. However, it is conceivable that the costs of disposing of radioactive fuel and decommissioning nuclear power stations may exceed current estimates. Furthermore, the cost of a major nuclear accident is unknown.[5]

Fuel Supply Considerations in Ontario Hydro's Expansion Programme

Ontario Hydro relied primarily on water power in the past, but has turned increasingly to thermal generation as the bulk of the economic water potential of Ontario has been harnessed. Water power now accounts for less than 30 per cent of Ontario's electric power generating capacity, and it is anticipated that this percentage will decline further under the present expansion programme, which proposes only a limited amount of future hydroelectric development.[6] In its thermal generation programme, Ontario Hydro has in operation or under construction large centralized facilities fuelled by natural gas, oil, coal, and uranium. One of the key elements determining future commitments is the availability of an assured supply of suitable fuel at competitive prices. However, as discussed in Chapter 1, the current energy situation has complicated Ontario Hydro's fuel picture in several ways. First, the cost of suitable fossil fuels has escalated sharply while, at the same time, the perceived security of supplies has decreased markedly; second, environmental constraints have restricted the development and wide-scale use of fossil fuels; and, third, the relative scarcity of non-renewable fossil fuels has stimulated a concern that they should be directed to uses other than electric power generation, for example, to serve as feedstocks to the petrochemical industry.

In its future fossil-fired generating programme, Ontario Hydro plans little further use of natural gas or oil. It sees limited potential in the use of oil-fired generating capacity in Ontario because of declining oil reserves in western Canada, rapidly escalating world oil prices, and the uncertainty of foreign supplies. The availability of oil to meet Ontario Hydro's present and planned oil-fired generating requirements, however, is reasonably assured through the export policy of the National Energy Board, which requires that domestic needs receive first priority. But the reliability of supply of domestic oil will depend, in the long run, on government action to encourage the development of additional frontier or tar sands oil. Ontario Hydro contracted for approximately one-half of its 1975-9 requirements from a refinery in eastern Canada that uses offshore crude, and it is possible that the utility will also use some residual oil from western Canadian crude refined in Ontario. The only oil-fired facility planned or under construction, the Wesleyville Generating Station at Port Hope, has been mothballed until after 1990.

Although some of Ontario Hydro's generating units are currently capable of being fired by natural gas, mainly to meet air-quality standards in Toronto, additional supplies of gas will be very costly and subject to competing demands. The use of such a "premium" fuel for the generation of electricity is undesirable, because natural gas can be used to better advantage in other applications. With these and other problems associated with the delivery of additional natural gas supplies, Hydro anticipates reducing its annual consumption from 50 billion cubic feet in 1976 to 10 billion cubic feet by 1980. The rising cost of gas is a major factor in this decision.

As a result, the fossil component of Ontario Hydro's expansion programme is based on coal. Coal with a sulphur content that meets environmental standards is available in the eastern United States, where it is in relatively short supply, and in western Canada, where it is plentiful. However, the supply from western Canada is constrained by the logistics and the expense of transporting large quantities of coal across the country. Other potential coal sources are located in Nova Scotia. Lignite deposits at Onakawana near James Bay have proven reserves estimated at 200 million tonnes. An engineering report prepared for the Government of Ontario has established the basic feasibility of installing about 1,000 MW of on-site generation at Onakawana.[7]

Ontario Hydro has contracted for the purchase of up to 13 million tonnes[8] of coal annually from the United States, and considers that the balance of its requirements can be met from the reserves of bituminous and sub-bituminous coal and lignite in western Canada. Although the combustion characteristics of low-quality coal and lignite pose certain technical problems when these fuels are used in existing stations, Ontario Hydro is carrying out studies and tests to determine the future potential of these resources for Ontario, and plans to blend lower-quality coal and lignite with U.S. coal for use in some of its existing stations.

Of all the fuels being used by Ontario for thermal power generation, only uranium is indigenous to the province in large quantities; consequently, Ontario Hydro's long-range expansion programme involves a substantial dependence on uranium. Existing contracts with Preston Mines Ltd. and Denison Mines Ltd. call for the delivery of 76,200 tonnes of uranium beginning in 1980 and continuing to the year 2020.[9] Hydro has other contracts for about 5,000 tonnes of uranium. The excess contracted supply of approximately 23,000 tonnes is adequate for the 30-year requirement of 4,000 MW of additional nuclear capacity beyond the currently committed programme.[10]

Summary

Electric power generation in Ontario grew during the first half of this century from a hydraulic, or renewable, resource programme to a thermal generation programme based on non-renewable resources. The growth in the demand for electricity is accounted for mainly by the greater convenience of this form of energy in meeting many of the requirements of a highly automated society. In addition, the use of electricity for space heating and water heating has increased – the former being a seasonal load on the system. Because generating capacity requires a large initial capital investment, the system does not particularly welcome seasonal loads, especially considering the thermodynamic losses that are inherent in the conversion of electricity to thermal energy. Energy storage technologies could decrease this imbalance (both seasonal and daily), but with a higher capital cost.

CHAPTER THREE

The Status of Present and Future Electric Power Generation Options for Ontario

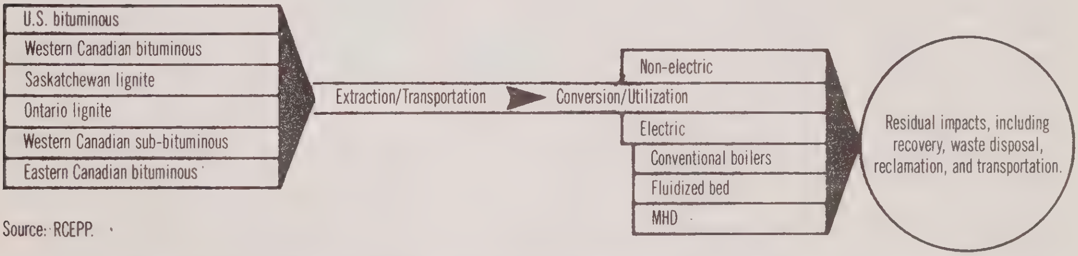
The central purpose of the Royal Commission on Electric Power Planning as outlined in its terms of reference is "to identify a long-term electric power strategy for Ontario and to consider its implications". This chapter explores the range of electric power generation options that are available to Ontario, both in the near term and in the longer term. The development of an electric power system cannot take place in isolation from other energy systems, since electric power generation is dependent on the availability of primary energy inputs. Furthermore, an electric power planning strategy requires an assessment of the available non-electric options and their potential to replace or be replaced by electric power. The non-electric energy options are discussed, for convenience, in Appendix A, while the potential for inter-fuel substitution is explored in Chapter 7.

As was suggested in Chapters 1 and 2, energy systems are characterized by a range of internal and external costs that arise from society's overall goals and objectives. This range of costs is not limited to the conversion process but extends throughout the fuel cycle, from initial extraction to waste disposal. Each step of the process requires both energy and capital input and has various impacts on the environment. Thus, the conversion of a fuel to electricity to perform certain tasks could lead to greater internal and external costs than would result from direct combustion of a fuel to perform the same tasks. However, a number of variables can affect this general rule, such as the nature of the end-use requirement, the duration of the demand, and the type of fuel that is used to produce the electricity.

Fossil Fuels

Coal

Figure 3.1 The Coal Resource



Source: RCEPP.

Availability of Fuel Supplies. Coal is the most abundant fossil fuel in Canada and in the world. Canadian coal reserves are estimated to be 76 billion tonnes.[1] This represents an energy equivalent of more than 1,000 times Ontario's total annual secondary energy consumption. The availability of coal is controlled largely by the mining, transportation, and environmental costs associated with it. Thus, only a fraction of Canada's estimated coal resources can be regarded as economically recoverable, at present, without significant and costly improvements in the logistics of this mode of energy recovery. From Ontario Hydro's perspective, on the basis of its 1979 load forecast, the coal requirement for electric power generation in Ontario is expected to grow from the 1978 level of 9 million tonnes to about 12 million tonnes per year by the year 2000 (see Table 3.1).

Table 3.1 Ontario Hydro's Coal Requirements Based on Its 1979 Expansion Plan

	Millions of tonnes of coal (30 GJ per tonne equivalent)	
Year	Estimated requirements	Minimum contract levels
1979	10.1	10.2
1980	9.2	12.9
1981	8.9	11.8
1982	9.2	11.6
1983	9.2	11.6
1984	9.8	10.9
1985	10.1	10.9
1986	9.8	10.9
1987	9.3	7.3
1988	9.5	8.2
1989	9.3	6.0
1990	9.5	5.9
1991	10.4	5.9
1992	10.7	5.9
1993	11.0	5.4
1994	12.2	2.9
1995	12.5	2.9
1996	12.4	2.9
1997	12.0	2.9
1998	11.5	2.9
1999	11.7	2.9

Source: Ontario Hydro, "1979 Review of Generation Expansion Program," Table 9-3, Alternative 6, March 1979.

Large reserves of bituminous coal exist in West Virginia and western Pennsylvania, with an electric power generating potential of 3,200 kW·h/tonne (assuming a conversion efficiency of 38 per cent).[2] While these and other U.S. coal reserves are extensive, projected U.S. requirements may limit their availability to Ontario Hydro. Present Hydro contracts for U.S. coal are indicated in Table 3.2.

Table 3.2 Present Ontario Hydro U.S. Coal Contracts

Company	Amount of coal
Consolidated Coal Company	5,442,000 tonnes/year (6,000,000 tons/year) to 1986
Eastern Associated Coal Corp.	2,267,500 tonnes/year (2,500,000 tons/year) to 1984
Various other companies	1,587,250 tonnes/year (1,750,000 tons/year) to 1980
U.S. Steel's Cumberland Mine	2,721,000 tonnes/year (3,000,000 tons/year) to 2008

Source: Ontario Hydro: Memorandum to RCEPP on fuel supply, 1976.

Estimates of western Canadian bituminous coal reserves in British Columbia and Alberta are measured at 7.2 billion tonnes, indicated at 33.4 billion tonnes, and inferred at 46.3 billion tonnes, for a total of 87 billion tonnes.[3] Of this, about 50 per cent is recoverable with present mining technology.[4] Western Canadian bituminous coal can generate 2,700-2,900 kW·h of electricity per tonne, assuming a 38 per cent conversion efficiency. It has an ash content of 10.5-18.5 per cent, and contains 0.3-0.5 per cent of sulphur.[5] To diversify its coal supply options, Ontario Hydro has recently contracted for about 2.5 million tonnes of western Canadian bituminous coal per year, even though this coal is 30 per cent more expensive than U.S. bituminous. This is largely because of the distance involved and the lower heat value of western Canadian coal. However, because of its lower sulphur content, expensive sulphur-removal systems are not required. Due to the higher ash content of western coal, Ontario Hydro proposes to blend western coal with lower ash content eastern U.S. coal for use at the Nanticoke Generating Station; this station's boilers were designed to burn coal with a lower ash content. Hydro's present western Canadian coal contracts call for the delivery of 2.5 million tonnes per year by rail to Thunder Bay, for shipment from there to Nanticoke. The overall transportation distance is about 3,500 km compared with 700 km for eastern U.S. bituminous coal.

In general, the constraints affecting utilization of western coal are the capital investment required to expand the coal transportation infrastructure; environmental damage caused by mining, transportation, and utilization; and the reluctance of other jurisdictions to absorb external costs to meet Ontario's energy needs. The substitution of coal for gas and oil is not a significant technological constraint, since many processes now using gas or oil for heat used coal prior to 1960. The present transportation

infrastructure has a capacity of 8 million tonnes/year from western Canada, which could generate 22,500 GW·h of electricity. The Ontario Ministry of Energy estimates that, by the year 2000, interprovincial transportation capacity in Canada could be expanded to 100 million tonnes per year.[6] This amount of coal could generate 280,000 GW·h of electricity, almost three times Ontario Hydro's 1978 electricity generation.

Saskatchewan has large quantities of lignite that could generate 1,500 kW·h of electricity per tonne. Lignite from Saskatchewan would be transported by rail to Thunder Bay for use in the Thunder Bay generating station and possibly at a later date at Atikokan.[7] Ontario Hydro has contracted for 910,000 tonnes of lignite a year for 15 years. Two 155 MW lignite-fired units at Thunder Bay are scheduled for operation in 1980 and 1981.[8]

The Ontario lignite reserve at Onakawana contains an estimated 200 million tonnes with an electric power generating potential of 1,100 kW·h per tonne. This could fuel more than 1,000 MW for 30 years at an 80 per cent capacity factor. The possibility of locating an electric power generating station on or near the mine site, as proposed by the Shawinigan Steag Company, is now being reviewed by the Ontario government.[9] In this way, because of low transportation requirements, fuel costs would be kept to a minimum. The site is also close to existing bulk power transmission lines; however, bringing the power out of the station to meet demands in the southern part of the province may require an upgrading of the present transmission line or the construction of an additional 500 kV line through the corridor.

If the station is built to supply electricity to the West System, then a stronger inter-tie, probably a double-circuit 500 kV line, would have to be built between the East System and the West System.[10] Some concerns have been expressed about the effect the generating station would have on regional air quality because of the poor atmospheric dispersal characteristics at that latitude. However, the lignite has very low sulphur content and emissions to the atmosphere would be relatively low. The three proposed 340 MW units would cost $1,200/kW, according to the Shawinigan-Steag study,[11] but fuel costs for an on-site generating facility would be relatively low.

Status of Coal-Fired Electric Power Generation Technologies. The combustion of coal to generate electricity in Ontario, using present technology, is expensive in terms of both fuel and environmental costs. Sulphur dioxide scrubbers to reduce environmental impact can increase generation costs by 10-20 per cent. Other proposals, such as pre-treating the coal or shifting to very-low-sulphur coal, are at least as expensive. By the year 2000, the development of new technologies such as fluidized bed combustion (FBC) and magnetohydrodynamics (MHD) could produce power from coal more efficiently and with less environmental impact.

In conventional pulverized fuel-firing, powdered coal is injected by an air blast and burned, and the ashes then fall to the bottom. In fluidized bed combustion, the fuel is combusted in an agitated bed of inert particles that are kept suspended and in turbulent motion by a rising flow of air. The main advantage of FBC over conventional technology is its reduced emissions. Limestone or dolomite is added to the bed to absorb 85-95 per cent of the sulphur in the fuel during combustion. The resulting calcium sulphate can then be removed from the bed for recycling or disposal. For the absorbing material to act, combustion temperatures must be lower than in conventional plants, which tends to reduce nitrogen oxide emissions. Higher heat-release and transfer rates mean that size and material requirements are reduced and plant efficiency is improved despite the lower combustion temperatures.

Atmospheric fluidized beds and pressurized fluidized beds (PFBC) have been designed and demonstrated. A pressurized system has higher heat-release and transfer characteristics, more sulphur absorption, lower nitrogen oxide emissions, reduced size and materials requirements, lower capital costs, and the ability to use a combined cycle incorporating both a gas and a steam turbine. A combined cycle such as this results in a much higher overall efficiency than a conventional steam turbine cycle. A 500 MW commercial PFBC plant proposed jointly by the American Electric Power Service Corporation, STAL-Laval Turbin AB of Sweden, and Babcock and Wilcox of Great Britain is expected to be in operation by 1990 achieving 39.4 per cent efficiency with very low emissions, using a combined cycle. Improvements in gas turbines and higher operating temperatures could raise the plant's efficiency to 42 per cent. Costs for plants of commercial size are expected to be significantly lower than those for a conventional plant. The capital cost of a 170 MW plant to be built by 1984, for example, would be about $600/kW in 1977 dollars.[12]

Table 3.3 summarizes some of the advantages of a fluidized bed combustion plant in comparison with a conventional coal-fired plant.

Table 3.3 Comparison of a Pressurized Fluidized Bed Combustion (PFBC) Electric Power Plant with a Conventional Coal-Fired Plant

Characteristics	PFBC plant	Conventional plant
Sulphur removal efficiency	95	85
Calcium to sulphur ratio	2.4	1.2
NO_x emissions (g/MW-h)	460	930
Efficiency	39-40%	34-35%
Steam generator volume (m^3/MW_{th})	4.8	15.4
Steel requirements (tonnes/MW_{th})	2.0	5.5
Construction period (years)	3	5
Capital Cost (1978$/kW)	625	710

Source: J.J. Markowsky and B. Wickstrom, "170 MW Pressurized Fluidized Bed Combustion Electric Plant", paper presented at the 6th Energy Technology Conference and Exposition, Washington, D.C., February 1979.

Due to the lower combustion temperature of PFBC, emissions of nitrous oxides are half those of a conventional plant. PFBC has a 5 per cent better efficiency, one-third of the steam generator volume, and one-third of the steel requirements of a conventional plant. Its capital cost on a commercial scale is estimated to be 88 per cent of that of a conventional plant.

Pressurized fluidized bed combustion will likely be available commercially for utility-sized applications of 500 MW and up by the year 2000. Compared with conventional coal plants, these plants would have lower capital costs due to reduced size, material, and lead time requirements; slightly lower fuel use due to improved efficiencies; and a significant reduction in emissions. The use of PFBC would make coal competitive with nuclear power for meeting loads of longer duration than is presently justifiable. A large-scale co-generation programme using PFBC could be competitive with nuclear power for meeting much of the base-load demand.

Electricity production in thermal generating stations involves a four-stage conversion process. Chemical or nuclear energy from combustion or fission is transformed to thermal energy, which is used to raise pressurized steam, which in turn drives a turbine (mechanical energy) that turns a generator to produce electric energy. The efficiency of steam turbine generation is limited by the laws of thermodynamics. In the conversion from thermal to mechanical energy, the energy transferred to the turbine cannot exceed the difference between the thermal energy in the steam entering the turbine and the thermal energy in the steam leaving it. This limits the efficiency of conventional generation, theoretically, to about 50 per cent. A conversion process that can avoid this "thermal bottleneck", that is, the conversion of thermal energy to mechanical energy, could achieve higher efficiencies. One such process is the fuel cell, discussed in Chapter 4, which converts chemical energy directly into electric energy. Another is magnetohydrodynamics (MHD), which converts thermal energy directly into electric energy.

MHD technology is based on the principle that when a gas is heated to a very high temperature, in the order of 5,000 C or more, electrons in the gas will be liberated; in the presence of an electric field, negative ions, or electrons, will flow one way while the positive ions that are formed when an electron leaves a neutral atom will flow the other way. If alkali metals, such as potassium or caesium, are seeded in the gas as a catalyst, the desired reaction can take place at much more manageable temperatures, in the range of 1,000-1,500°C.

In an MHD plant, the flowing hot gas serves as a conductor, and a current is induced to flow in the gas by a superconducting magnet. While a conventional generator produces AC current, an MHD generator produces DC current because the magnetic field on the conductor does not alternate as it does in a conventional generator.

Due to the corrosive effects that occur at these high temperatures, clean fuels such as hydrogen, natural gas, and fuel oil operate best, but the long-term attractiveness of MHD will probably depend on its ability to use coal as a fuel. MHD generators will operate at efficiencies of 20-30 per cent; however, in combination with a steam turbine driven by the heat from exhaust gases, a combined cycle efficiency of 50-60 per cent can be achieved.

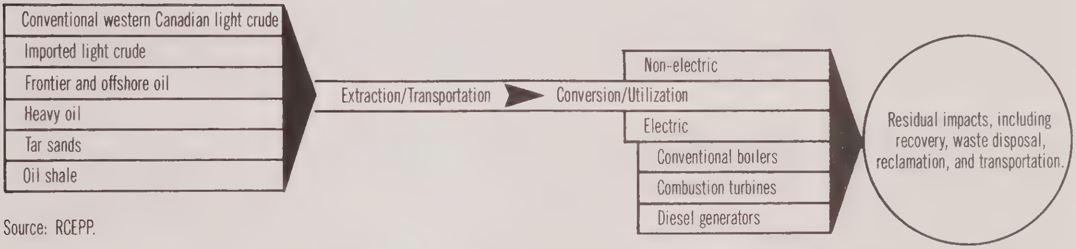
Both the U.S. and the U.S.S.R. anticipate commercialization of MHD during the 1990s. The U.S. Department of Energy programme calls for a 250 MW thermal MHD/steam pilot plant operating by

1990. This coal-burning combined cycle plant would have an overall efficiency of 45 per cent. It is expected that MHD plants will achieve an ultimate efficiency of 50 per cent. Whether or not this target can be reached depends on the development of temperature- and corrosion-resistant materials and a superconducting magnet technology.

Estimates indicate that a coal-fired MHD plant operating with 50 per cent efficiency could have an energy cost of 31 mills/kW·h (compared with 29 mills/kW·h for a current conventional fossil plant). The capital costs of the MHD component are expected to be in the $150-$200/kW range; however, due to its greater efficiency, an MHD plant will be much less sensitive to rising coal prices than a conventional coal-fired station. Furthermore, because an MHD plant requires less fuel per unit of electricity output, and because the gaseous stream must be kept clean to avoid corrosion at the high temperatures used, air emissions are not as much of a problem. A 2 MW plant went into operation at the Argonne National Laboratory in Chicago in July 1979.

Oil

Figure 3.2 The Oil Resource



Source: RCEPP.

Availability of Fuel Supplies. In 1978, oil supplied 42 per cent of Canada's primary energy requirements. This represented 100 million m^3 (650 million barrels) or 270,000 m^3 (1.8 million barrels) per day.[13] Ontario accounted for about one-third of Canada's total oil consumption in 1978. Although there is some oil production in Ontario (1,600-1,700 barrels per day in 1978), over 99 per cent of Ontario's requirement is supplied from outside the province.

The National Energy Board estimates established remaining reserves of light crude oil in western Canada to be approximately 5.8 billion barrels as of January 1, 1978, while the annual report of the Canadian Petroleum Association, dated March 1979, estimated reserves at 6.9 billion barrels. Exploration has greatly increased in recent years, and it is anticipated that recoverable reserves could ultimately be as much as 24 billion barrels.[14] One example of current exploration efforts, the West Pembina find, could yield 500-2,000 million barrels.

Canada east of Montreal is served almost exclusively by imported oil. In 1978 Canada was a net importer of 360,000 barrels per day. Security of supply is a major concern in view of current global uncertainties. World oil prices at the end of 1979 ranged from $18-$23 U.S. or $21-$27 Canadian.[15] The price increase during 1979 was more than 55 per cent and the world market remained volatile.

Recovery costs for frontier oil are high compared with conventional sources because of much higher exploration, drilling, and transportation costs. Estimates by the Geological Survey of Canada are 9.1 billion barrels with 90 per cent confidence, 16.3 billion barrels with 50 per cent confidence, and 32 billion barrels with 10 per cent confidence.[16] A recent find by Dome Petroleum in the Arctic is rumoured to be very large, perhaps in excess of a billion barrels, but arctic oil would be very expensive to produce and deliver.

Exploration activity is also taking place offshore along the Atlantic continental shelf. A discovery off the coast of Newfoundland, about 325 km southeast of St. John's, by a consortium headed by Chevron, is rumoured to be in the 6-9 billion barrel range, which is greater than present proven western Canadian reserves. However, early drilling announcements in September of 1979 appeared not to support this optimism.

Crude oil with a viscosity near the heavy extreme of conventional crude is partly recoverable by existing methods, but pumping is necessary to maintain the flow. Tertiary recovery methods that are under development could greatly increase recovery factors. For example, crude oil in place in the Lloydminster area of Alberta and Saskatchewan is estimated to be between 6.0 and 18.7 billion barrels. Ultimate

recovery of 20-30 per cent appears to be technically feasible at that location, and as a result recoverable reserves are estimated to be in the range of 2-5 billion barrels. Although tertiary recovery methods are costly, the steadily increasing price of a barrel of crude oil is beginning to make this investment attractive. Oil sands reserves at Cold Lake in Alberta are estimated to have 165 billion barrels in place, while the Athabasca Sands could have up to 800 billion barrels in place. Ultimate recovery using existing technology is anticipated to be in the range of 15-30 billion barrels from Cold Lake and 40-140 billion barrels from the Athabasca Sands. Oil sands producers are guaranteed the current international price for their product. The Syncrude plant, which began operation in September 1978, has a capacity of 129,000 barrels/day, while the Great Canadian Oil Sands plant produces about 50,000 barrels/day. A 140,000 barrel/day plant to be built by a consortium headed by Shell has been approved and it is expected that another to be built by Imperial Oil will be approved soon. Each is expected to cost about $5 billion (1979 dollars). With present mining techniques, 26 billion barrels of tar sands oil are believed to be recoverable, and production of up to 1 million barrels/day would be possible. *In situ* recovery techniques could eventually make 100 billion barrels recoverable,[17] and long-term production could be 2-4 million barrels/day although it is unlikely to exceed 0.5 million barrels/day by the year 2000.

New Brunswick has some oil shale reserves, estimated at 3 billion barrels. As these reserves are much smaller than those in the U.S., it is likely that the necessary extraction technologies will be developed in the U.S. It has been suggested that the oil shale could be burned directly in generating stations in the Maritimes.

Status of Oil-Fired Electric Power Generation Technologies. Ontario Hydro has one 4 × 500 MW oil-fired station at Lennox, just west of Kingston, and has postponed the completion of a 2 × 547 MW station at Wesleyville, near Port Hope, at least until 1990. Due to the higher cost of oil in comparison with U.S. bituminous coal, oil-fired generation in Ontario is used only for meeting peak demand. In 1978, oil produced 1,739 GW·h, or 1.6 per cent, of Ontario Hydro's total electricity production. In 1979 the Lennox station is scheduled to operate at 7.5 per cent of its attainable capacity, or 7 per cent of maximum continuous rating.

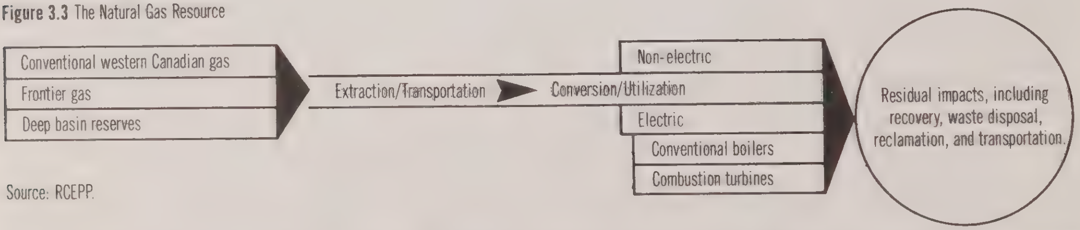
Modern oil-fired stations operate at a net thermal efficiency of 37 per cent, which is close to optimum theoretical performance, given thermodynamic limitations. Oil-fired generation using residual oil generally requires the use of precipitators to remove particulates from flue gas. If imported oil with a sulphur content of 2.5 per cent is used, it may be necessary to use scrubbers or blend the oil with western Canadian oil, to control sulphur dioxide emissions.

Light fuel oil is used in combustion turbines in the Ontario Hydro system, but because of low efficiencies and high fuel costs these turbines are operated only in the reserve mode. The development of advanced combustion turbines could make this use more attractive by the 1990s.

For decentralized electric power requirements, in remote areas where a hook-up to the provincial power system is prohibitively expensive, small diesel-fired generators can be used. Diesel fuel for electricity generation is expensive, however, and it is only viable in isolated areas if no other feasible options exist.

Natural Gas

Figure 3.3 The Natural Gas Resource



Source: RCEPP.

Availability of Fuel Supplies. In 1978, 1.5 trillion cubic feet (tcf) or 42 billion m^3, of natural gas were consumed in Canada, supplying 18 per cent of primary energy. Natural gas comes from several sources, each varying greatly in recovery and production costs. Table 3.4 gives the estimates of producibility by the National Energy Board (NEB) published in February 1979.[18] Ontario produces only a small quantity of natural gas – about 12.3 billion cubic feet in 1978, most of it from Lake Erie.

Table 3.4 Producability Estimates of Natural Gas (billions of cubic feet/year)

Year	Conventional areas Low	NEB	High	Frontier Low	High	Total Low	High
1979	3,020	3,533	3,700	–	–	3,020	3,700
1980	3,106	3,695	4,010	–	–	3,106	4,010
1985	3,290	3,455	5,120	–	1,350	3,455	6,470
1990	2,693	2,981	5,500	1,096	3,780	2,981	9,280
1995	2,214	2,341	5,262	2,140	6,145	2,341	11,407
2000	1,663	1,937	4,888	1,701	8,646	1,937	13,534

Source: "Canadian Natural Gas, Supply and Requirements", National Energy Board, February 1979.

Proven reserves of conventional western Canadian gas are about 66 trillion cubic feet (1,900 billion m^3), while total recoverable conventional reserves in western Canada are estimated to be 147 tcf (4,160 billion m^3). In a submission to the National Energy Board, Amoco Canada Petroleum Company Ltd. gave an estimate of 200 tcf of economically recoverable reserves, taking rising fuel prices into account. Net Canadian domestic use in 1978 was 1,473 billion cubic feet (bcf), of which 329 bcf was used residentially, 826 bcf was for industrial use, and 319 bcf was for commercial use. Of the gas used industrially, an estimated 165 bcf was used in the petrochemical industry and 120 bcf was used for electricity generation. Exports amounted to 881 bcf.[19] The Toronto city gate (wholesale) price in August 1979 was $2.15 per standard thousand cubic feet (mcf).

Proven natural gas reserves in the Mackenzie delta and arctic islands were about 14.5 tcf at the end of 1978, according to the NEB. The Geological Survey of Canada (1977) has estimated frontier gas reserves to be 150 tcf with 50 per cent confidence. The cost of these reserves is expected to be high. For example, gas delivered from the Alaska North Slope to California is expected to cost $5.50/mcf, compared with $2.15/mcf for Alberta gas delivered to Toronto. It has been suggested by the pipeline industry that, to justify the cost of a pipeline, reserves of 10-20 tcf would have to be found. The proposed pipeline from the Alaska North Slope through the Yukon and Alberta had an estimated cost (1979) of $15 billion.

Alternatively, gas could be liquefied or converted to methanol and transported by tanker from the high Arctic to the east coast, as has been proposed by Petrocan. The anticipated capital cost, in the order of $1.5 billion, is much lower than for a pipeline; lower reserve requirements might therefore justify such an investment. After regasification, the delivered cost of gas using this transportation method is expected to be $3.80/mcf (1978 dollars). However, the transportation and handling of liquefied natural gas poses serious risks due to the possibility of explosion. The conversion of natural gas to methanol before it is transported has a much lower risk.

Deep basin reserves in northeastern British Columbia and northwestern Alberta may have a potential of 400 tcf, according to Canadian Hunter Exploration Ltd. in its submission to the NEB. This gas is found in "tight" sands of low porosity and low permeability, usually 2,000 to 3,000 m underground. The costs of this gas may be quite high. At 1979 well-head prices, 50 tcf is estimated to be economically recoverable. At twice the present well-head price, 100 tcf may be recoverable. However, development will require advanced fracturing methods. Research is now being done on ways of enhancing the permeability of these formations by hydraulic or chemical explosive fracturing and directional drilling. Unless there is some progress in the development of these technologies by the early 1980s, exploration in "tight" sands areas may be reduced.

Status of Gas-Fired Electric Power Generation Technologies. There is some opposition to the use of high-quality fuels, such as natural gas, for combustion in utility boilers where efficiencies are less than 40 per cent compared, for example, with the 70 per cent efficiency for combustion in home furnaces. Furthermore, some oppose the use of natural gas except as a petrochemical feedstock, even though only 10 per cent of present Canadian domestic natural gas use is for that purpose.

The capital cost of a natural gas station is 70-80 per cent of that of a coal station because environmental control costs are lower, there are no storage costs, and boiler requirements are smaller. Fuel costs, however, are at least 30 per cent higher than for U.S. bituminous coal. In the Ontario Hydro system, only the R.L. Hearn Generating Station in Toronto uses natural gas. At Hearn, four 100 MW units and one 200 MW unit use natural gas exclusively, while three 200 MW units use natural gas from May to October and coal from November to April. In 1978, gas-fired generation produced 2,079 GW·h, or 2.0 per cent, of the electricity supplied by Hydro, compared with 4,051 GW·h, or 3.9 per cent of the electric-

ity supplied in 1977.[20] The gas-fired units operated at a 26.5 per cent annual capacity factor in 1978, down from 51.4 per cent in 1977. Due to the age and inefficiency of the Hearn station, the cost of natural gas, and the availability of cheaper generation, Hydro is taking the 4 × 100 MW Hearn units out of service. The units will, however, be maintained at a level that will allow them to be quickly brought back into service. The 1979 planned capacity factor for Hearn, before Hydro's decision to remove the 4 × 100 MW units from service, was about 14 per cent, with planned generation of less than 1,500 GW·h.[21]

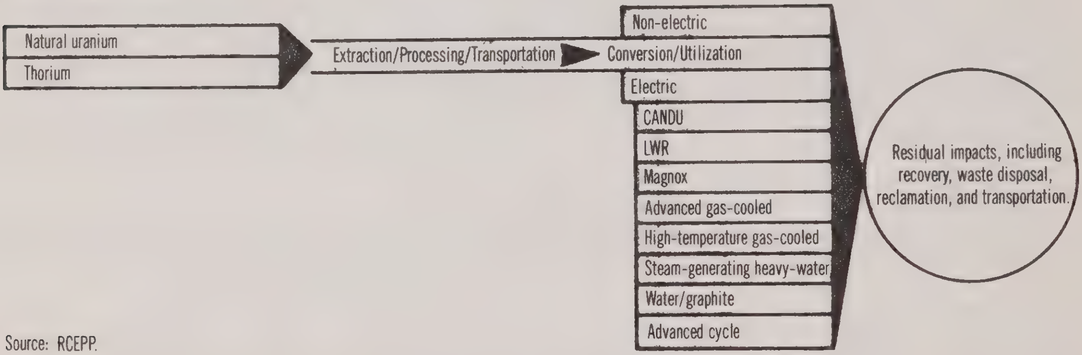
Natural gas can also be used in combustion turbines. Potential improvements in gas turbine efficiency, and the possibility of combining the gas turbine cycle with the steam turbine cycle, could increase the attractiveness of this option. In addition, gas turbines have short construction lead times – usually about one year.

Combined cycle plants on a small scale are available now, and larger plants are being developed. The development of an advanced gas turbine would make the combined cycle plant even more attractive. The U.S. Electric Power Research Institute (EPRI) estimates that advanced gas turbines using water-cooled, ceramic blades and a high-temperature heat exchanger should be available by 1990. These units would have higher efficiencies and could operate with a wider variety of fuels.

Nuclear Energy

Nuclear Fission

Figure 3.4 Nuclear Fission



Source: RCEPP.

Availability of Fuel Supplies. The Energy, Mines and Resources Canada report, *1978 Assessment of Canada's Uranium Supply and Demand*, indicates the scale of Canadian and Ontario uranium reserves (see Table 3.5). The annual availability of uranium is essentially limited by the production capability, as indicated in Tables 3.6 and 3.7, and the extent to which production has already been committed to export. Approved outstanding Canadian uranium exports totalled 63,000 tonnes as of January 1, 1979.[22] Ontario's total reserves in the three highest-confidence categories equalled 369,000 tonnes of uranium as of January 1,1979. The world price of uranium rose from about $10 (U.S.) per kilgram in 1973 to about $112 per kilogram early in 1978, when the slowdown began in U.S. nuclear expansion. It has remained steady since then.

Table 3.5 Canadian and Ontario Uranium Reserves in Tonnes Recoverable

	Canada[a]	Ontario[b]
Measured (100% confidence level)	80,000	49,000
Indicated (80% confidence level)	155,000	74,000
Inferred (70% confidence level)	302,000	235,000
Prognosticated (unspecified confidence level)	426,000	178,000

Notes:
a) Canadian reserves estimated recoverable at up to $175/kg.
b) Ontario reserves estimated recoverable at up to $160/kg.
Sources: Canada: Energy, Mines and Resources Canada, "1978 Assessment of Canada's Uranium Supply and Demand", EP 79-3, June 1979. Ontario: Energy, Mines and Resources Canada, "1977 Assessment of Canada's Uranium Supply and Demand," EP78-3, June 1978.

Table 3.6 Estimated Future Annual Canadian Uranium Production in Tonnes

1978	6,803 (actual)	1984	13,500
1979	6,900	1985	14,400
1980	7,200	1986	14,500
1981	9,000	1987	14,500
1982	9,900	1988	14,700
1983	11,000	1989	15,400
		1990	15,500

Source: Energy, Mines and Resources Canada, "1978 Assessment of Canada Uranium Supply and Demand", EP79-3, June 1979.

Table 3.7 Estimated Future Annual Ontario Uranium Production in Tonnes

1977	3,400
1980	4,700
1985	4,700
1990	5,500
1995	5,200
2000	4,400

Source: David Robertson and Associates Ltd., "A Brief Review of Uranium Supply and Demand". Submitted to the Select Committee of the Legislature on Ontario Hydro Affairs, December 8, 1977.

Ontario Hydro's recent contracts with Denison and Preston total 76,000 tonnes of uranium. A CANDU reactor operated for 30 years at an 80 per cent capacity factor requires 4.2 tonnes of uranium metal per megawatt of capacity. On this basis, the uranium metal contracted from Denison and Preston by Ontario Hydro is enough to fuel 18,000 MW of capacity for 30 years. This is equivalent to the capacity committed up to and including the Darlington Generating Station, plus 4,000 MW of capacity.[23] However, contracted annual delivery levels are not uniform over the 40 years covered by the two contracts. The contracted delivery levels increase as production is expanded, reaching a peak delivery level of 3,000 tonnes in 1993. This is enough to fuel over 21,000 MW of capacity annually. The contracts allow for expansion of annual production to fuel up to 27,000 MW or curtailment of production to fuel only 12,000 MW.

Although uranium is one of the few energy resources indigenous to Ontario, some key factors affecting the future price and availability of uranium are beyond direct provincial control. The federal government has primary jurisdiction over the entire nuclear fuel cycle as well as over uranium export policy. While guaranteeing that sufficient reserves are in place to meet future utility requirements, the federal government does not specify the grade of uranium or the price at which it will be available. The somewhat pessimistic assessment of uranium availability presented in the Commission's *Interim Report on Nuclear Power in Ontario* was based on the latest official Ontario Hydro expansion programme (LRF 48A). Since then, reduced demand forecasts have resulted in a reduced expansion programme and a correspondingly smaller projected demand for uranium. The expansion programme based on the 1979 load forecast calls for just over 25,000 MW of nuclear capacity in 2000, compared with the 47,000 MW planned under LRF 48A. If Ontario were to rely on uranium indigenous to the province, then supply would probably be adequate to fuel 25,000-30,000 MW of nuclear capacity to the year 2010, assuming that annual production can be maintained in the 3,500-4,000 tonne range and that there are no further exports beyond current commitments (see Figure 3.5).

Fig. 3.5: p. 37

Status of the Technology – CANDU. Nuclear reactor development began in Canada at the end of World War II. The ZEEP (zero energy experimental pile) began operation in September 1945, followed by a heavy-water-moderated research reactor that achieved criticality in July 1947. A demonstration 22 MW reactor at Rolphton began producing electricity in 1962, followed by the first reactor of commercial size, a 206 MW facility at Douglas Point that commenced operation in 1967. Between 1971 and 1973, the four 514 MW units of Pickering A came on line, and as of January 1979 all four 746 MW units of Bruce A were in service. Table 3.8 indicates the extent to which CANDU technology is used throughout the world.

Table 3.8 Committed and Planned Deployment of CANDU Reactors

Station	Date of first power	Units	Capacity (MW)	Location
Nuclear power demonstration	1962	1	22	Rolphton, Ontario
Douglas Point	1967	1	208	Tiverton, Ontario
Pickering A	1971-3	4	2,056	Pickering, Ontario
Gentilly 1[a]	1971	1	250	Trois Rivieres, Quebec
Kanupp	1971	1	125	Karachi, Pakistan
Rapp 1	1972	1	203	Rajasthen, India
Bruce A	1976-9	4	2,984	Tiverton, Ontario
Gentilly 2[a]	1979	1	600	Trois Rivieres, Quebec
Lepreau	1980	1	600	Point Lepreau, New Brunswick
Cordoba	1980	1	600	Cordoba, Argentina
Pickering B	1981-3	4	2,064	Pickering, Ontario
Wolsung	1983	1	600	Wolsung, South Korea
Bruce B	1983-7	4	3,076	Tiverton, Ontario
Darlington	1987-90	4	3,524	Bowmanville, Ontario
Cernovoda[b]	not known	4	2,400	Cernovoda, Romania
Total			19,312	

Notes:

a) Gentilly 3, planned by Hydro-Québec but not scheduled, has an uncertain fate as the present Quebec government favours further development of Quebec's hydraulic resource. Recent announcements have ruled out any further nuclear development before 1995, even at a 7 per cent per annum growth rate. The James Bay project, coming on line in the early 1980s, will produce up to 10,000 MW. It is believed that a further 15,000 MW could be developed in Quebec more economically from hydraulic than from nuclear sources.

b) The present commitment by the Romanian government is to purchase four CANDU units and perhaps eventually up to 16 units. The site of the first station is Cernovoda.

Source: "Why CANDU? Its achievements and prospects", Atomic Energy of Canada Limited, RCEPP Exhibit 28-4; and RCEPP.

The CANDU-PHW reactor is fuelled with natural uranium oxide and is moderated and cooled by heavy water. Two alternate approaches for which research, development, and demonstration have been done are the CANDU-BLW, or boiling-light-water-cooled, system, and CANDU-OCR, or organic-liquid-cooled, system. A 250 MW CANDU-BLW unit, Gentilly 1, came into service in Quebec in 1971 but has experienced numerous operating problems and was taken out of service permanently by Hydro-Québec in 1979.[24] In addition, a small experimental CANDU-OCR unit was built at the Whiteshell Nuclear Research Establishment in Manitoba.

The core of a CANDU reactor consists basically of hundreds of horizontal pressure tubes, containing natural uranium fuel pellets, clad in zirconium alloy sheathing and arranged in bundles. A large volume of relatively cool low-pressure heavy water surrounds the pressure tubes, acting as a moderator. High-pressure heavy water flows through the pressure tubes, extracting heat from the bundles. The fact that the CANDU reactor uses natural uranium means that it consumes fuel faster than light-water reactor systems, and its design must therefore incorporate on-line fuelling. This feature has tended to increase the "availability" of CANDUs compared with other types of nuclear reactors; shut-down times for refuelling are not required.[25] The adaptation of the CANDU to use slightly enriched uranium has been proposed as one way of achieving a higher burn-up rate with lower fuel consumption. Technically, CANDU performance has been excellent, and Pickering A has consistently out-performed competing reactors in terms of capacity factors achieved. However, partly as a result of the Three Mile Island accident in the U.S., concerns have also been raised in Ontario about the safety and public acceptance of CANDU nuclear stations. At the end of 1979, a select committee of the Ontario Legislature was considering CANDU reactor safety and a parliamentary committee has been proposed to examine all aspects of the CANDU fuel cycle. As in other jurisdictions, a technically and socially acceptable solution to the problem of the ultimate disposal of uranium mill tailings and spent fuel continues to be a key prerequisite to public acceptance of the nuclear fuel cycle.

Other Principal Reactor Technologies, The light-water reactor(LWR), which is the most widely used type of reactor in the world, was first developed in the U.S. This reactor is fuelled by uranium oxide enriched to a U-235 concentration of about 3 per cent. It is moderated by light water and cooled by either pressurized or boiling light water. By 1980 there will be an estimated 205,000 MW of installed capacity of light-water nuclear reactors throughout the world.[26]

The use of enriched uranium fuel in LWRs reduces station capital costs by avoiding costs associated with heavy-water production. However, the enrichment process is expensive and energy-intensive, and it results in higher consumption of uranium per unit of electricity produced (1.6-1.8 times that of a

CANDU). On-line fuelling is not possible in this type of reactor, which has generally resulted in lower station availability.

The Magnox reactor, developed in the U.K., is fuelled by natural uranium metal, moderated by graphite, and cooled by pressurized carbon dioxide. The reactor is housed in a steel or pre-stressed concrete pressure vessel. Installed Magnox capacity totals 8,000 MW in the U.K. and France.[27] The main advantages are its use of natural uranium fuel and its on-line fuelling feature. The carbon dioxide coolant used in this design has resulted in extensive corrosion of steel components in the highly radioactive environment within the reactor, and, as a result, France has abandoned this gas-cooled concept.

The advanced gas-cooled reactor (AGR) is fuelled by 2 per cent enriched uranium oxide; it is moderated by graphite and cooled by carbon dioxide. In the U.K., a capacity of about 6,600 MW of this type of reactor is expected to come on line before 1980.[28] Because steel cladding is used, higher operating temperatures and higher efficiencies are possible. The reactor is contained in a pre-stressed concrete pressure vessel that is believed to be so safe that a containment building is not required. The development of this type of reactor has been delayed by technical difficulties and it is likely that it will be operated below rated power levels because of corrosion problems similar to those encountered in Magnox reactors, and others where prolonged exposure to high levels of radioactivity has led to embrittlement and stress corrosion effects.

The high-temperature gas-cooled reactor (HTGR) is fuelled by uranium carbide, moderated by graphite, and cooled by helium. Only a few operational reactors have been built – two in West Germany, two in the U.S., and one in Britain. As the fuel is uranium carbide, which has a higher melting temperature than uranium oxide, the core can be operated at much higher temperatures. The fuel is in pellet form and there are no metal pressure tubes in the core; as a result, there is much less neutron loss from absorption in metal than in other reactors. Efficiencies of 40 per cent, much higher than for other types of reactor, can be achieved by the HTGR because of its higher operating temperatures and greater neutron efficiency. Since the fuel is bonded with the graphite moderator, a major fuel meltdown is impossible. To date there has been little operating experience with this kind of reactor.

The steam-generating heavy-water reactor (SGHWR) is fuelled by 2-3 per cent enriched uranium oxide clad by zirconium, moderated by heavy water, and cooled by light water. This reactor has advantages and disadvantages similar to those of the CANDU, although it is cooled by boiling light water and uses enriched uranium. The SGHWR uses a pressure tube design as opposed to the pressure vessel concept. Present plans call for about 4,000 MW to be installed in the U.K.[29]

The water/graphite reactor developed in the U.S.S.R. is fuelled by 1.8 per cent enriched uranium oxide, moderated by graphite, and cooled by light water. Very little information has been published concerning this type of reactor.

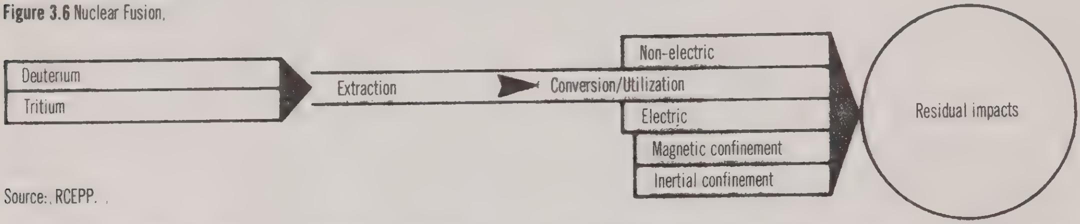
Advanced Fuel Cycle Reactors. These reactors are designed to extend the effective uranium supply in the world by converting fertile materials such as uranium-238 and thorium-232 into fissile materials, such as plutonium-239 and uranium-233. An advanced cycle reactor is designed to "breed" fissile material from non-fissile but fertile isotopes. In this way, up to 60 times more energy can be generated from the same amount of uranium. Atomic Energy of Canada Limited (AECL) has proposed a thorium-233 thermal converter development programme, in which modifications to present CANDU reactors are expected to be minor; however, commercial chemical separation and reprocessing technology must still be developed. AECL's advanced converter programme is aimed at developing a self-sufficient thorium cycle within 25 years.[30] The net thermal efficiency of a thorium-233 CANDU-type reactor is expected to be similar to that of a present CANDU reactor, in that about 29 per cent of the heat generated will be converted to electricity. A Science Council of Canada[31] report has estimated that development costs will be in the order of $1.75 billion over 25 years. Two reprocessing technologies and two fuel-fabrication technologies will have to be developed commercially. These processes will result in the production of highly radioactive liquid wastes that will have to be contained and disposed of. At the same time, this development will pose serious security and proliferation risks because highly fissile material will have been isolated in concentrated form.

Liquid metal fast-breeder reactors (LMFBRs), on the other hand, will differ greatly from present generation reactors. In this design, neutrons are not moderated or slowed down. A heavy coolant, liquid sodium, would be used, since it is less likely to slow down neutrons and has a higher cooling capacity. The first U.S. commercial-scale LMFBR is not expected to be operational until the next century. LMFBRs are expected to have a 40 per cent net thermal efficiency due to the higher heat-absorbing capability of

sodium. While the U.S. breeder programme has been delayed, other countries, notably France, Japan, the U.K., the U.S.S.R., and West Germany, are proceeding with breeder technology because of the uncertainty about uranium supplies. The U.K., France, and the U.S.S.R. have breeder reactors operating in the 250-350 MW range. The SUPERPHENIX, a 1,200 MW breeder reactor, is expected to begin operating in France in the early 1980s.

Nuclear Fusion

Figure 3.6 Nuclear Fusion.



Source: RCEPP.

Availability of Fuel Supply. If technological and materials problems can be overcome, nuclear fusion could virtually be a renewable source of energy, because it would use the hydrogen that is available in water as a fuel. Fusion involves the fusing of two light atomic nuclei with high enough initial kinetic energies to overcome the electrostatic repulsion of positive ions. The fusion reaction that results in the greatest release of energy is the fusion of deuterium and tritium (two heavier isotopes of hydrogen) to form helium and a free neutron. In the fusion process, some of the mass of each nucleus is converted into energy according to Einstein's mass-energy equivalence relation. Thus, the sum of the masses of the tritium and deuterium nuclei is greater than the sum of the masses of the nucleus of the helium atom and the neutron that is released. This difference in mass appears as energy according to the formula $E = mc^2$. Although only 1/7,000 of the hydrogen atoms on earth are deuterium atoms, the amount of energy that can be released per reaction, combined with the great amount of hydrogen in the world, makes it a potentially vast energy resource. It has been estimated that one km^3 of water could produce more energy than all of the fossil fuels on earth.[32]

Status of Fusion Technology. As already mentioned, in a fusion reaction two light nuclei are fused together to create a more stable, larger nucleus, thereby releasing binding energy in the form of heat. Fundamentally, containment, or control, of the fusion reaction requires the development of materials capable of withstanding temperatures of about 100,000,000 K. At present, two methods of containment have been proposed, for which research and development work is being undertaken.

Magnetic confinement fusion contains the reaction in the form of a plasma, or ionized gas, inside a strong magnetic field that holds the particles to the lines of the field. The material requirements are awesome. For example, in order to contain the 100,000,000 K reaction the magnet would have to operate at the temperature of liquid helium, which is approximately 4 K. For the reaction to produce net energy, three criteria would have to be met simultaneously: temperature – an ignition temperature of 50-100 million K would have to be achieved; density – in the order of a quadrillion of fuel ions would have to be compressed within a cubic centimetre; and duration – the reaction would have to be sustained for 0.1 to 1 second. The Tokamak Fusion Test Reactor at Princeton University in New Jersey has come closest to achieving these criteria.

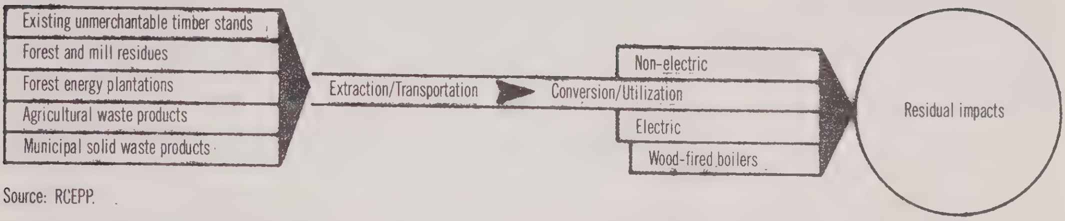
The second approach is inertial confinement fusion, in which small frozen pellets of deuterium-tritium (1 mm in diameter) are dropped one by one into a chamber and are bombarded by a focused laser pulse. The heat transfer is so rapid that the inertia of the pellet will hold it together while the fusion takes place. Lasers powerful enough to do this have not yet been developed. However, work on this concept is being done with relativistic electron beams and with high-speed ion beams to maximize the energy transfer.

Few researchers are predicting the availability of fusion before the turn of the century. The Electric Power Research Institute in the U.S. predicts commercial availability by 2010. To date, most research and development work has been done on magnetic confinement technology. Inertial confinement fusion is not expected to have an impact on the electricity supply system until 2025.[33] The Science Council of Canada, in its report *Energy – R&D, in Search of Strategy*, predicts that widespread use of nuclear fusion will not occur in Canada until 2050.[34] Capital costs for fusion reactors are expected to be high; estimates range from \$1,000-\$1,600/kW of electricity (1976 dollars). Canada has had little more than a monitoring programme of fusion research to date.

Renewable Energy

Biomass Energy

Figure 3.7 The Biomass Energy Resource



Source: RCEPP.

Availability of Fuel Supply for Wood-Fired Electric Power Generation. Biomass energy, which can be derived from organic materials such as wood and waste products, has considerable potential for Ontario, which has 80 million hectares (198,636,000 acres) of land classified as forested. In a submission to the Commission, the Department of Fisheries and Environment Canada suggested that, of the 25 million hectares (60 million acres) of timber stands that are available for the production of forest products, approximately 10 per cent, or 2.5 million hectares, could provide enough biomass to fuel 10,000 MW of installed generating capacity.[35]

One possibility that has been suggested for large-scale utilization of biomass energy is the "energy plantation", in which large areas of fast-growing hybrid poplar would be grown and managed, using advanced agricultural technology. A study by Morris Wayman and Associates[36] has suggested that such a concept could be applied in southeastern Ontario, where much of Class 3 and 4 agricultural land is no longer in production. According to Wayman, up to 1,500 MW of installed generating capacity could be fuelled by wood from energy plantations. Wayman has since reduced his estimate substantially and now considers 200 MW a more realistic estimate of the electric power generating capacity that could be fuelled by biomass energy plantations by the year 2000.[37]

Status of Wood-Fired Electric Power Generation Technology. Wood is a renewable resource, and with appropriate management it is well suited for a number of energy applications including the direct combustion of wood for heat, the combustion of wood chips for electricity production, and the conversion of wood into methane or methanol. Considering the variety of possible applications, it is easy to understand why there is some difficulty in defining the most advantageous use of this resource for Ontario. The problem is somewhat compounded by possible competing uses for wood fibre and waste wood materials.

The pulp and paper industry consumes 17 per cent of Ontario's industrial electricity. The majority of Ontario's pulp and paper mills could become energy-self-sufficient by using mill and forest wastes as fuel to produce steam and electricity. A number of such schemes are already in existence in Canada, the U.S., and Europe. Where transmission facilities are available, a provincial utility may be justified in purchasing the excess electricity produced during a mill's low-load periods. From the standpoint of resource availability and efficiency, this approach has some merit; it not only provides energy for the mill but offers a very simple and convenient solution to the forest underbrush problem, which can be an obstacle to reforestation efforts. The major issue is whether or not the industry can afford the capital expenditure required to implement such a scheme.

For several years the city of Burlington in Vermont has derived a portion of its electricity requirement from a 10 MW wood-fired boiler. The boiler is used in conjunction with two other 10 MW boilers that burn other fossil fuels.[38] The city is now exploring the possibility of using a 50 MW wood-fired boiler to provide all of its electricity. In Ontario, the town of Hearst has proposed a similar scheme, by which mill residues would be transported from sites within a 60-mile radius of the town to be burned in a 20 or 30 MW electricity generating station. An economic analysis of the Hearst project, done by Acres Consulting Services Ltd., indicated that, in relation to current electricity prices, the economics of such a scheme are questionable. The consultants did not rule out the possibility that the break-even point will be reached, but warned that, if current electricity pricing structures remain the same, a break-even point will only be reached in the somewhat distant future. This is probably true of many small-scale decentralized electricity generating options (i.e., the smaller the output capacity per unit, the smaller the return on investment).

Availability of Fuel Supply from Municipal Solid Waste. As urban population increases, our cities are increasingly burdened by the problem of garbage disposal. Municipal waste products are dumped in large open areas, but as these areas are used up the disposal problem will become a critical one. Incineration of municipal solid waste (MSW)[39] is a solution that not only reduces the waste to a fraction of its original volume, eliminating the need for large landfill sites, but also produces useful energy. MSW contains approximately 50 per cent moisture and ash and has a calorific value of approximately 4,300 BTU per pound, while certain combustible waste items, including paper, cartons, rags, and wood scraps, have a moisture content of 25 per cent and a calorific value of 6,500 BTU per pound. In Ontario, MSW is produced in the order of 7-8 $\times 10^6$ tonnes per year, which is equivalent to approximately 12×10^6 barrels of oil per year, or the equivalent of 800 average annual megawatts.

Status of Electric Power Generation Technology Using MSW. The potential of converting MSW to energy has already been recognized in Ontario, as evidenced by the "Watts from Waste" programme sponsored by the Ministry of the Environment. The concept behind this programme was, essentially, to separate combustible from non-combustible waste items for incineration in an electricity- or steam-producing facility. In Metropolitan Toronto, this process permitted hybrid coal/MSW fuelling in one of the coal-fired boilers at Lakeview Generating Station. The Watts from Waste programme was started in 1977 but has since been suspended.

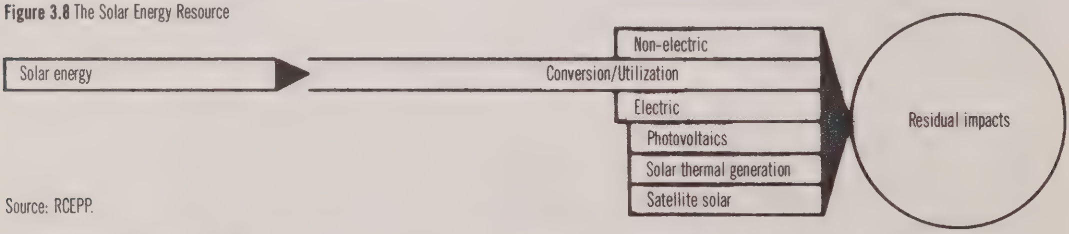
Except for large cities, landfill, sanitary or otherwise, generally provides the most economical method of waste disposal. However, environmental impacts caused by water, air, and soil pollution, as well as land requirements, are considered to be major limitations. The alternative to landfill for Ontario is incineration. However, small incinerators generally require the use of some auxiliary fuel and have little or no heat recovery. Large incinerators, on the other hand, generally do not require support firing and, furthermore, can produce substantial quantities of useful thermal energy. It is likely that initial development of the energy potential contained within MSW will require the construction of large incinerators with heat-recovery systems, concurrent with sufficient planning to ensure that there is a demand in the vicinity for the thermal energy produced by the plant.

The East Hamilton solid waste reduction unit (SWARU) represents a significant departure from established waste-incineration processes. In this system, all the waste that arrives at the plant is shredded by large hammer mills and then moved by conveyors to storage tanks where it is drawn off from the bottom of the tanks. From here the waste product is pneumatically injected into a furnace where approximately half of the waste burns in suspension. Electrostatic precipitators are used to clean the flue gas. While the boiler used in the SWARU system is of conventional design, auxiliary systems at the plant are equipped with turbine drives to utilize as much of the steam as possible, and the excess is sold. SWARU's two units have the capacity to burn 600 tonnes of refuse per day, while producing 200,000 pounds of steam per hour, to be used for space heating. At this level of steam production it is also feasible to produce electricity simultaneously, using co-generation.

In the future, it is anticipated that packaged incineration and energy systems will be widely used in small-scale applications, using fluidized bed combustion (FBC). FBC is well established for waste-wood incineration and is attractive because of its ability to burn a wide variety of wastes including liquids. In this process, combustion occurs at a low temperature, which reduces the extent of pollution. However, FBC systems still require fuel preparation and the input of pressurized air, which tends to increase the operating costs.

Direct Solar Energy

Figure 3.8 The Solar Energy Resource



Source: RCEPP.

Availability of Supply. Daily solar radiation in Ontario fluctuates from 1 to 6.4 kW·h/m^2 at a given location with a mean solar insulation level of 3.5 kW·h/m^2. Average solar radiation in the province ranges from 2.9 kW·h/m^2 along parts of Hudson Bay to about 4 kW·h/m^2 along Lake Erie. While solar energy is available, its diffuse and intermittent nature makes capture and storage costly.

Status of Solar Electric Power Conversion Technologies. While solar energy can be used for a number of low-temperature heat applications, such as residential heating, it can also be used directly to produce electricity.

Photovoltaics are, essentially, semiconductors whose electrons can be removed by small increases in temperature, thereby producing electricity when sunlight shines on them. The ability to induce current flow in photovoltaic cells depends on the electron behaviour and lattice structure of the material.

Various types of solar electric cells, or photovoltaics, have been demonstrated; however, availability of the technology on a commercial scale is limited by high manufacturing costs. The U.S. Department of Energy has set a target for the production of photovoltaic cells at a cost of $0.50 per peak watt by 1985 (1976 dollars), and the completion of 500 MW of photovoltaic capacity by 1986. Table 3.9 indicates the U.S. Department of Energy's goals for photovoltaic development.

Table 3.9 The U.S. Department of Energy's Goal for Photovoltaic Developments

Time period	Solar cell cost[a] $/peak watt	Production MW/year	System cost[b] $/W	cent/kW·h
1982	2	10-20	5	30
1986	0.5	100-500	1	6
2000	0.1-0.3	10,000-50,000	0.8	5

Notes:

a) 1975 applications are in the sun belt. Northeastern region costs would be double.

b) System cost includes solar collector, photovoltaic convertor, power conditioning, distribution, and output.

Source: "Improvements in the Performance of a Low Cost Thin Film Solar Cell", John D. Meakin. Paper presented to the 6th Energy Technology Conference and Exposition, Washington, D.C., February 1979.

The proposed range of photovoltaics includes single- or poly-crystal sulphide, amorphous silicon, cadmium sulphide and gallium arsenide. Single crystal cells of silicon have achieved 20 per cent efficiency, and the more expensive gallium arsenide cells have achieved efficiencies of 26 per cent. It would cost less to manufacture thin film cells, but efficiency would be in the 10 per cent range. The silicon photovoltaic cell is perhaps the best understood. In the U.S., it is hoped, the cost of producing silicon may be reduced from $65 per kilogram to $10 per kilogram by 1986, with efficiency improving from 11 per cent to 14.4 per cent. For photovoltaics to have an impact in the 1990s, a cost of $0.10 to $0.30 per peak watt[40] will be necessary. Materials research and development will certainly play a key role. For example, the reduction in capital costs of silicon cells per peak watt from $15 to $10 resulted from technical improvements, primarily in the process of growing single silicon crystals and slicing them for application in photovoltaic cells. It is believed that costs can be further reduced by the use of thin films that might be only a fraction of the thickness of the 10 mm slices used in current technology.

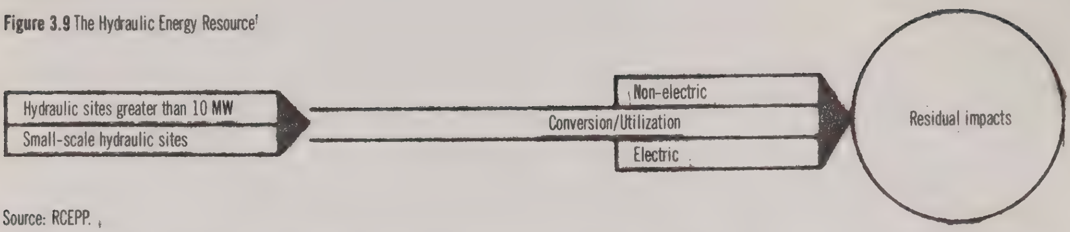
Due to the intermittent nature of the source of energy, photovoltaic cells will require either a storage system or an auxiliary system. At an estimated price of $2 per peak watt for the total system, it has been suggested that the cadmium sulphide cell could be competitive in southwestern California by 1986 for electric power generation at the point of end use. Because of the inherent efficiencies, the decentralized application of solar photovoltaics appears to be of greatest importance. There are several demonstration projects, ranging in size from 20 to 500 kW.

Solar-thermal power generation is achieved by means of mirrors or lenses that track the sun, directing a concentrated solar flux onto a receiver. In this way temperatures in the order of 500°C can be achieved – sufficient to produce high-pressure steam for use with a steam turbine to produce electricity. In the U.S., a demonstration project is being developed in New Mexico. Although the economics of this technology are uncertain, Aerospace Corporation estimates a cost of $0.0048/kW·h in 1991 dollars at the point of generation.[41] It has been estimated that a 1,000 MW solar-thermal plant would require approximately 14 km^2 of collector area.[42]

This concept incorporates arrays of photovoltaic cells on a satellite in geosynchronous orbit, about 22,000 miles from earth. Electricity is transmitted from outer space via microwave to a large receiving and rectifying antenna on earth. It is unlikely that satellite solar power will become economically viable within this century. Development costs are high, and the capital cost is estimated at about $10,000/kW. A large-scale programme being proposed by the National Aeronautics and Space Administration could have development costs of $76 billion.[43]

Hydraulic Power

Figure 3.9 The Hydraulic Energy Resource[†]



Source: RCEPP.

Availability of Supply. Ontario has 107 operating hydroelectric generating stations with a combined installed capacity of 7,069 MW; Ontario Hydro owns 70 of these, with a total installed capacity of 6,420 MW.

The potential for additional conventional hydroelectric stations with a capacity of more than 10 MW lies mostly in northern Ontario. This is far from load centres and would require extensive transmission facilities. In addition, many of the sites conflict with the interests of native settlements. The Albany and Severn rivers could provide 2,143 MW and 580 MW of average annual power, respectively. In addition, new sites and extensions of old sites with capacity greater than 10 MW could add a further 700 MW of average annual power. Thus, estimated additional conventional hydraulic potential in the province is in the order of about 3,400 average annual megawatts.

The remaining large-scale sites on the Albany and the Severn were last studied in 1976. They were found to be uneconomic due to high capital and transmission costs. It is probable that these projects will only become economic if the costs of other forms of generation, principally nuclear, rise more rapidly.

In 1978, hydroelectric stations in the province generated 35,834 GW·h, or 37.4 per cent of the total energy generated. If all additional hydraulic sites in the province were developed, this energy could be doubled. However, high capital costs, long transmission requirements, and environmental factors could delay development.

The development of large-scale generating facilities has in many cases eliminated the requirement for small-scale hydraulic sites for the province. However, looking to the future, it is possible that these small-scale hydraulic sites may once again become an important energy resource. In Ontario, there are some 1,000 sites with an energy potential of less than 10 MW, totalling about 800 MW. Because of the varied nature of these sites, decisions concerning the cost-effectiveness of constructing small-scale generating facilities must be made on an individual basis. It is conceivable that 50 to 300 MW of small-scale hydraulic potential could be brought on line by the year 2000 depending upon a number of factors, such as the remoteness of the location and the competing agricultural or recreational uses.

Status of Hydroelectric Power Technology. The conversion of hydraulic energy to electric energy involves few losses. Up to 90 per cent efficiency can be achieved depending upon the length of piping from the source to the plant. Hydraulic units have poor efficiency at low load factors and so are generally run at high loadings and shut down completely when not required. This can easily be done with hydraulic units; they can be started and stopped and loaded and unloaded quickly. Plants may be operated at base load, as in the case of run-of-the-river plants, or flow may be retained for a period of time in order to operate units for 16 hours, 8 hours, or 1 to 2 hours per day, depending on the size of the unit and the economics involved. At present, of the 6,420 MW of installed hydraulic capacity in the Ontario Hydro system, about 40 per cent, or 2,800 MW, is run in the base-load mode at close to 95 per cent of capacity. The rest is run in the intermediate and peaking modes.

The equipment in a hydraulic unit is more reliable than other generation equipment. However, there is a reliability problem caused by variations in rainfall, wind, and ice formation. Also, because hydroelectric stations are often far from load centres, there is a need for long transmission lines, and this can reduce the overall reliability of the system. The advantages of small-scale hydraulic units include their suitability for peaking-load requirements, and the fact that, in many locations, the need for additional transmission facilities is eliminated. What has plagued the development of small-scale hydraulic facilities in the past is the high initial capital cost. The utility finds it difficult to justify small-scale hydraulic units because of the amount of planning required per unit of energy output. Many small, scattered generating stations of less than 10 MW might be difficult to feed into the grid and to control. They would present Ontario Hydro with load-planning problems if they were all connected to the grid. If such facilities were operated privately, feeding energy into the grid when they had excess power and

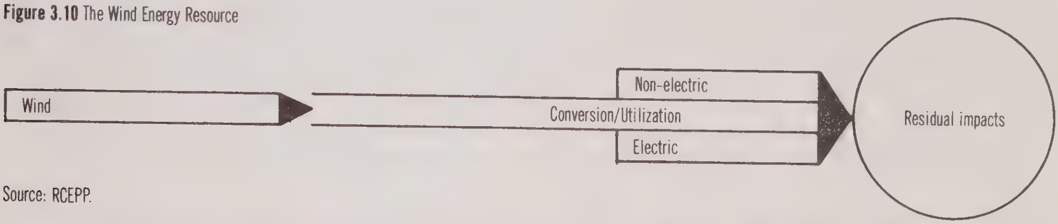
drawing power out of the grid when they needed it, changes in billing and operating practices would be required.

The cost of small-scale hydraulic facilities can run to anything from $700 to $2,000 per kilowatt of installed capacity. Peaking hydro developments with capacity factors of less than 20 per cent and costing as much as $1,000 to $1,500 per kilowatt could be more economical than residual oil or combustion turbines.

Ontario Hydro is working with Grand Council Treaty 9 Indians to establish a series of demonstration projects using small-scale hydraulic turbines. Some municipal utilities have indicated an interest in reclaiming decommissioned hydraulic generating stations. Orillia Light and Power is an example of such a utility. In addition, collaboration with the conservation authorities throughout the province may permit the development of hydraulic energy at flood-control dam sites by using low-head turbines.

Wind Energy

Figure 3.10 The Wind Energy Resource



Source: RCEPP.

Availability of Supply. Theoretically, the energy from wind could be used to supply all of Ontario's present requirements. However, the intermittent and dispersed nature of wind makes it difficult and expensive to harness. Available wind energy varies considerably in Canada and in Ontario. Figure 3.11 indicates the major wind régimes across Canada. In general the greatest potential for wind energy is in the coastal and more northerly regions of the country. Table 3.10 indicates the wind energy potential measured at five locations across Ontario.

Fig. 3.11: p. 38

Table 3.10 Wind Energy Measured at Five Ontario Locations (kilowatt hours)

Location	Windiest month	Least windy month	Annual total
London	165	48	1,272
Ottawa	108	45	946
Sudbury	222	138	2,331
Thunder Bay	112	50	1,015
Toronto	126	50	1,070

Note: Energy at 100 per cent conversion efficency. Windmill span assumed to be 1 m². Tested 10 m above the ground in an open area.
Source: Atmospheric Environment Service, Ontario Region, Report SSU-78-9.

In Ontario, much of the understanding about wind energy from a feasibility standpoint is based upon work of the Ontario Research Foundation (ORF) in collaboration with the Ontario Ministry of Energy. One ORF report suggests that certain remote locations, particularly in the northern part of the province, may be suitable for wind energy conversion systems.[44] Another potential area, according to the report, is the Great Lakes region. In an Environment Canada report, Sudbury is mentioned as the area with the best wind-power potential in Ontario.[45]

Status of Wind Technology

Over the last century many farmers in Ontario have used windmills to harness mechanical power and in some cases to generate electricity. In recent years, the National Research Council has guided the development of a domestically produced vertical axis wind turbine which, so far, has seen only limited application, mainly in the Arctic. In the U.S., wind-power is re-emerging as an important energy option, especially in rural applications, and some progress has been made towards overcoming control problems that arise when wind-energy devices are connected with a power grid.

The efficiency of wind turbines is highly variable, depending on the type of unit and the minimum speed at which the turbine can begin producing power. The intermittent nature of wind greatly inhibits the overall working efficiency of wind turbines unless adequate energy storage facilities are provided. Furthermore, as wind generators operate at their installed capacity only when the wind is

blowing at or above their design speed, overall performance is limited to a load factor that is dictated by the average wind velocity in a specific location. The maximum theoretical energy recovery for any wind-driven device is about 60 per cent of the energy contained in the airstream intercepted by the turbine.[46] However, the overall efficiency of an individual wind turbine system is not likely to be more than 35-40 per cent.

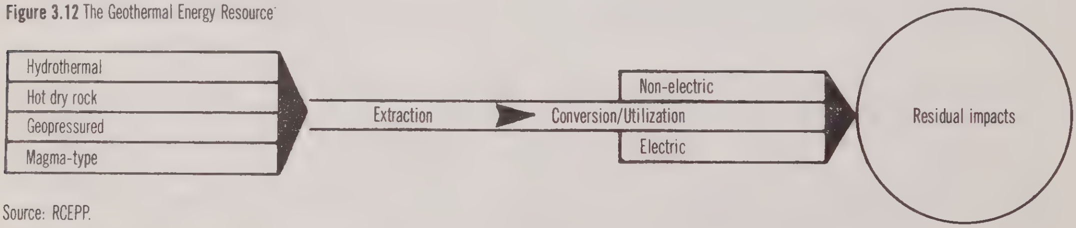
Wind energy devices for smaller decentralized applications are commercially available. Larger-scale utility-operated systems may be commercially developed within five years. Mass production would reduce construction lead times; however, the transporting of equipment to remote locations and the extensive meteorological analysis required for proper siting of wind turbines could lead to delays. Generally, an energy storage system or an auxiliary energy system is required, unless the wind generator is connected with the power grid. However, this connection could create serious load-planning uncertainties for the utility. A number of storage options have been demonstrated, including battery storage and electrolysis of water to produce hydrogen. Wind power has been used to provide electricity with diesel generators as a back-up system. The U.S. Department of the Interior has made a preliminary study that uses 49 large-scale (2 MW capacity) wind turbines in conjunction with the Colorado River storage scheme.[47] The site of the study, Medicine Bow, Colorado, has a high average wind velocity.[48] Wind energy would be used to recharge the capacity of the Colorado River storage scheme. At Medicine Bow, it is windiest when the water level is low, so charging capability is available when it is most needed. This project appears feasible for two reasons – first, because there is an appropriate storage medium; and, second, because of the possibility of large-scale mass production of wind turbine components, which would greatly reduce the overall cost of the project.

Another U.S. study, being conducted by Westinghouse, is evaluating the potential of offshore wind power in the Great Lakes. The mid-lake wind velocities are high, but the technology for harnessing wind in such offshore locations is very expensive. Westinghouse has assessed the cost of constructing floating or fixed platforms on which wind turbines could be located. It has also assessed the feasibility of a variety of energy storage systems, including hydrogen storage and battery storage.

For Ontario, it is generally agreed, the application of wind-energy technology has greatest potential in remote northern areas. An assessment by the ORF has suggested that large wind generators (100 kW and larger) have the potential to save diesel fuel and reduce energy costs in some northern communities.[49] In view of the significant price increases of fossil fuels and the large cost associated with the transportation of these fuels to remote locations, a decentralized approach to the implementation of wind-energy conversion systems appears to be logical for Ontario. Ontario Hydro has tested a 10 kW wind turbine on Toronto Island and is developing a 50 kW demonstration in the Sudbury area.

Geothermal Energy

Figure 3.12 The Geothermal Energy Resource



Source: RCEPP.

Availability of Supply. Geothermal energy is found where faults and fractures in the earth's crust contain heat from the interior of the earth close enough to the surface to permit exploitation. Geothermal energy can be used for district heating or for generating electricity with a steam turbine. The four types of geothermal energy are hydrothermal, hot dry rock, geopressured, and magma-type.

Hydrothermal resources exist where water or steam convection currents transport heat from deep in the earth's interior to a depth where it is accessible by drilling. These pockets can be vapour- or liquid-dominated and are known to exist in California, Wyoming, Italy, Japan, Iceland, Mexico, and New Zealand. Areas where there are faults or fractures causing heat to rise to the surface but where no subterranean water exists are referred to as hot dry rock resources. In North America, these are generally found along the Pacific coast.

Geopressured resources are found where water occurs at higher pressures (3,000-14,000 psi or 200-950 atm) and lower depths (1,500-6,000 m) than is characteristic of hydrothermal resources. Geopressured areas have been identified in the vicinity of control areas around the Gulf of Mexico.

Magma-type formations are found where molten rock exists at depths of approximately 30 km and temperatures of 500-1,700°C.

Canada's geothermal energy resources are found primarily in the western sedimentary basin and are estimated to be 360 times as large as known Canadian gas reserves. Most of the information concerning western geothermal energy has been derived from data obtained during drilling for oil and gas. There has not been any indication thus far to suggest the presence of a significant quantity of easily accessible geothermal energy in Ontario, and extremely deep geothermal resources are not economically exploitable.[50] However, beyond the year 2000, and as technical expertise becomes available, this situation may change.[51]

Status of the Technology. Only high-quality vapour-dominated hydrothermal reserves are used commercially to generate electricity in North America, but both vapour- and liquid-dominated hydrothermal energy are used elsewhere in the world. The two cycles under consideration for liquid-dominated hydrothermal use in steam turbines are flashed steam, whereby steam is formed by sudden pressure reduction, and the binary cycle in which a heat exchanger is used.

500 MW of commercial generating facilities are being operated at the Geysers steam reservoir in California by Pacific Gas and Electric, and there are plans for an additional 1,400 MW by 1985. Other utilities in the U.S. have plans for an additional 200 MW from liquid-dominated sources by 1982.[52] Already developed in areas especially favoured by geology, high quality hydrothermal resources will probably be widely developed by the 1985-1990 period. Large-scale development of low-grade sources is not likely before the year 2000.

Summary

There is no doubt that Canada is fortunate in having a number of energy opportunities. Current trends are towards the continuing development of all economic sources of oil and natural gas, and exploration in the frontier regions. However, it must be recognized that other energy resources, such as coal, nuclear, hydraulic, solar, and biomass, require further development. This will certainly require a co-ordinated effort by industry and government.

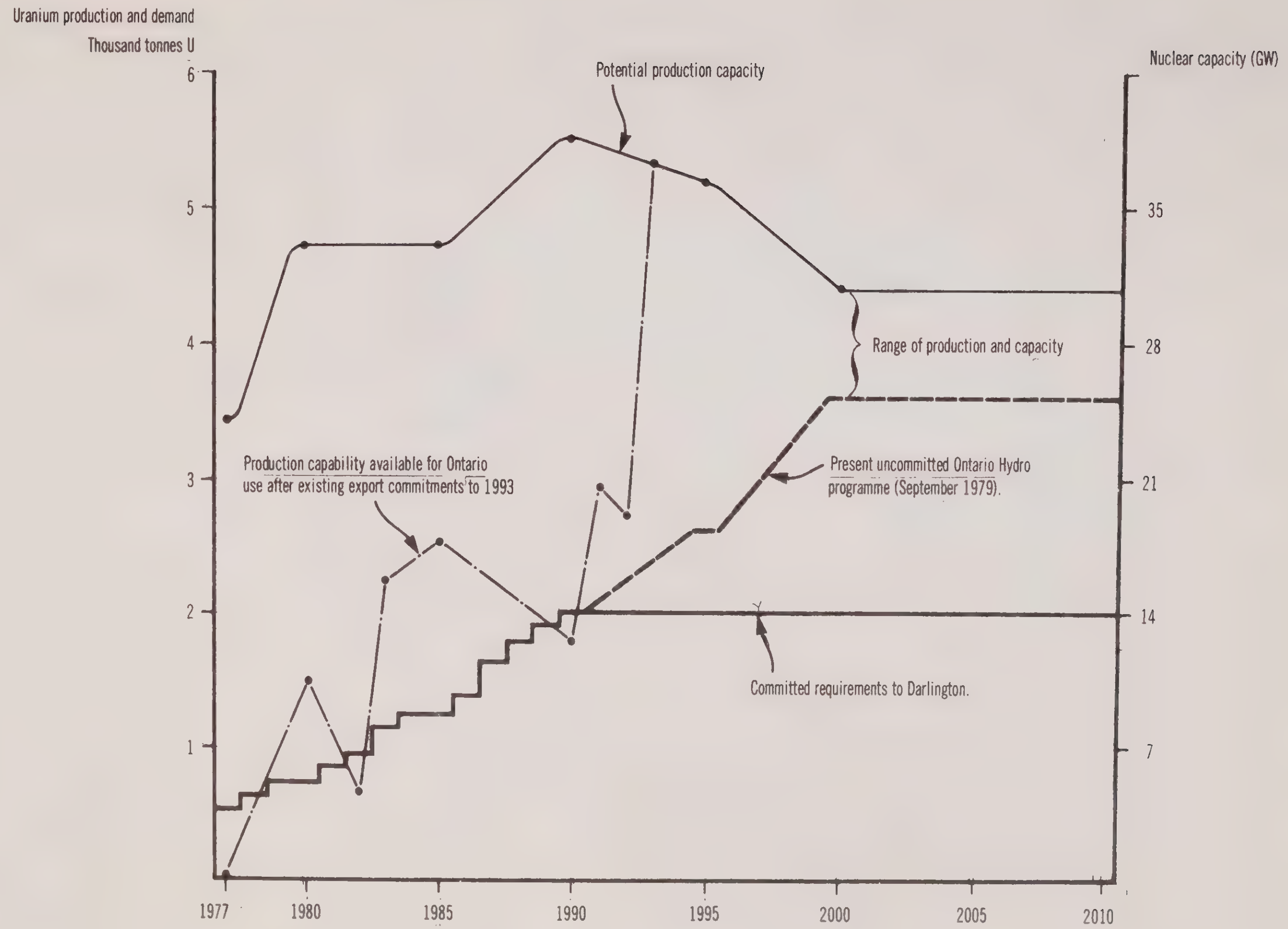
Table 3.11 summarizes the status of the energy options that are of major importance to Ontario, with emphasis on electric power generation.

Table 3.11 Energy Resources of Major Importance to Ontario

Energy Resource	Status of Development	Major Constraints
Oil Natural gas	Available from existing reserves and imports. New exploration and development efforts are extensive and could lead to national oil and natural gas self-sufficiency during the 1990s.	Ontario is dependent on resources from outside the province.
Coal	Coal is available from a number of sources including the Onakawana reserves, but acceptable conversion technologies are expensive and in the early stages of development. Fluidized bed combustion should be feasible by 1985 for use in meeting co-generation requirements. MHD will be another possibility by the mid 1990s. Coal gasification and liquefaction have long-term viability as an alternative to conventional liquid and gaseous fossil fuels.	Acid rain. Greenhouse effect.
Nuclear	Electric power generation technology is available. Management and control technology throughout the fuel cycle still requires further development. Contracted uranium is sufficient to meet the future needs of the utility at least to the year 2000.	Radioactive waste storage and management. Public acceptance. Capital cost.
Biomass	Combustion technology is available and is being used in some forestry operations. Co-generation using wood chips could lead to energy self-sufficiency in the pulp and paper industry.	Time-lag and the availability of capital to modernize and re-equip the forest products industries. Lack of sufficient reforestation programmes.
Solar	Its passive aspects are a major contribution to conservation, but it is difficult to retrofit. Active solar heating systems are similar but more expensive. Solar options are attractive, but, for Ontario, demonstration is not likely before 1990.	The majority of solar-electric R&D programmes are being done outside Canada. Capital cost is still a consideration.
Hydro	New large sites in Ontario are limited to northern areas. Greatest immediate potential exists in the form of interconnections with other provinces. Low-head sites have potential in some locations.	Interprovincial co-operation. Transmission facilities. Land rights.

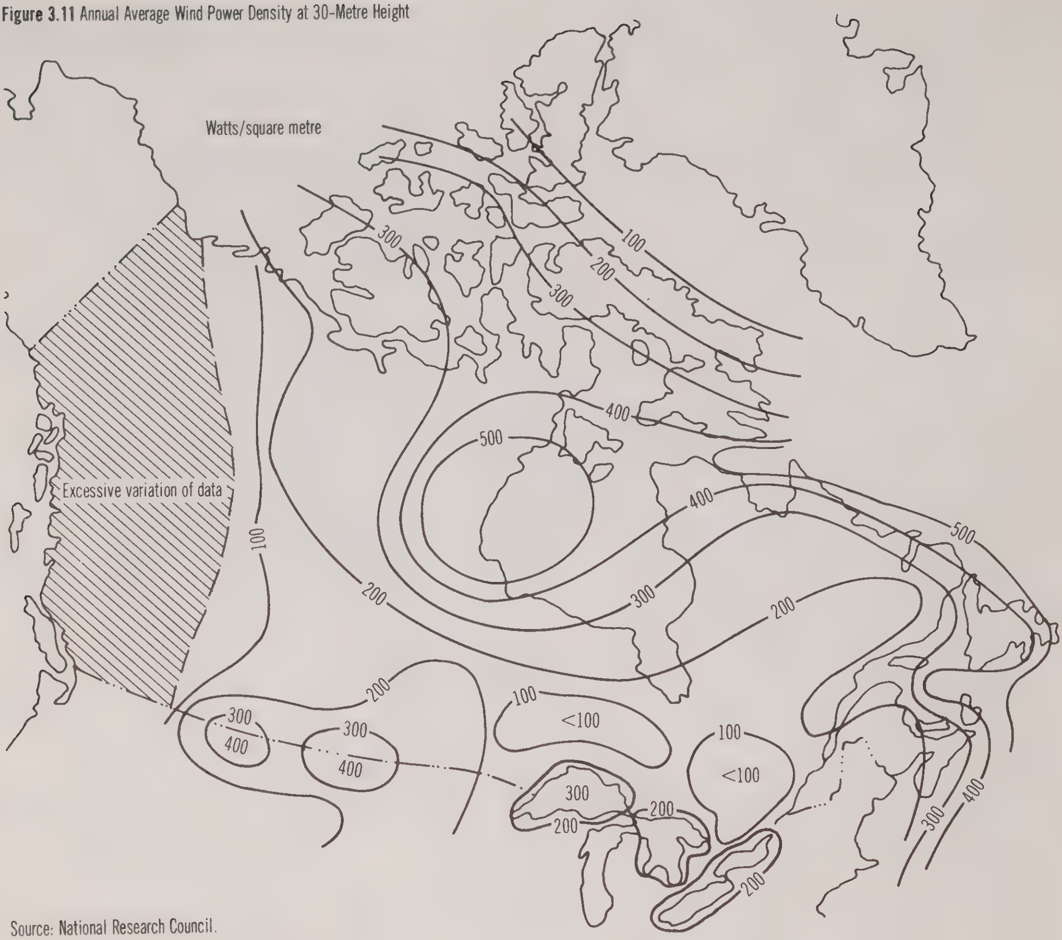
Source: RCEPP.

Figure 3.5 Ontario Annual Potential Uranium Production Capacity and Requirements



Source: RCEPP.

Figure 3.11 Annual Average Wind Power Density at 30-Metre Height



Source: National Research Council.

CHAPTER FOUR

Energy Storage

Fig. 4.1: p. 44

As energy is extracted, distributed, and used in a variety of ways, it must be stored at various points throughout the energy production and utilization cycle. Figure 4.1 indicates the points at which energy storage takes place in a typical fuel cycle. The most familiar type of energy storage is the physical storage of raw or processed fuels, for example, in the coal piles of Ontario Hydro or the large oil tanks of a refinery. There are, in addition, a number of ways of storing energy closer to the points of end use, such as the domestic hot-water heater and the gasoline tank of an automobile. These offer convenience and potential economic advantages to both the user and supplier of energy.

The opportunities for new applications of energy storage are numerous, particularly at a time when conventional energy supplies are increasingly uncertain. Energy supply options that can reduce dependence on non-renewable forms, such as solar space heating and water heating, are intermittent and require energy storage devices and/or auxiliary supply systems. Similarly, the use of energy storage devices to power electrical vehicles could significantly reduce oil consumption. In addition, energy storage technologies can improve the operation and economics of the electric power system.

Energy storage technologies may be classified broadly as mechanical, thermal, chemical, or electromagnetic. An example of mechanical energy storage is the use by an electric power utility of a pumped hydraulic scheme, such as the pumped hydro development operated by Ontario Hydro at Niagara Falls. Another example is the compressed-air scheme developed in West Germany by the Nordwestdeutsche Kraftwerke, where off-peak electricity is used to compress air into two subterranean salt caverns; during peak-demand periods, air is released and used in the burning of high-grade fuel in a gas turbine. More electricity is produced with a given amount of fuel, because the gas-turbine generator need not be used to power a compressor.

Thermal energy storage is perhaps best exemplified by the use of water reservoirs or rock chambers to store heat. This technique is used in most solar space-heating schemes and in some European communities, where off-peak electricity is used to charge ceramic brick storage heaters.

Batteries and hydrogen-energy storage systems are examples of chemical energy storaqe. The electrical input/output and the compactness of batteries makes them potentially the most useful of all energy storage methods. Hydrogen generation, storage, and reconversion can be achieved by a number of combinations of different methods. A prototype fuel-cell design developed in the U.S. consists of an electrolysis stage and a hydride storage stage and has an overall potential electrical output of 12.5 kW.

The idea of superconducting magnetic energy storage is still at an early stage of development. Although several big superconducting magnets have been built for research applications, the capital cost is extremely high, and it is only when storage capacity exceeds 10,000 MW·h that the economics even begin to be attractive[1].

Energy Storage and the Electric Power Utility

Methods of storing electricity once it has been generated are very expensive; consequently, electricity is usually generated only as it is needed. Due to variations in the demand for electricity, both seasonal and daily, sufficient generating capacity must be built to meet the annual peak demand and provide reserve margin that will ensure an adequate level of reliability. While certain types of generation, such as hydraulic and nuclear, are inexpensive when operated at high capacity factors, their high capital costs make them expensive if they are used only intermittently. Fossil-fuel generating stations, which have higher fuel costs but lower capital costs, are generally preferred for meeting intermittent and peak loads. However, average electric power generation costs could be reduced if the stations with high capital but low energy costs were operated at higher capacity factors. For example, it is conceivable that by 1990, if the rate of growth of the demand for electricity continues to fall, a portion of Ontario Hydro's nuclear and hydraulic generating capacity may not be needed to meet base-load demands all of the time. It might then be advantageous to use the resulting excess capacity to charge storage devices, thereby reducing dependence upon more expensive fossil-fuel peaking capacity.

The major obstacles to the utilization of energy storage systems are their cost, their land requirements, energy losses in charging and discharging, and uncertainties as to the future cost differential between

peak and off-peak power. In Ontario, the development of energy storage systems using off-peak electricity could increase the utilization of indigenous energy sources of supply such as uranium and falling water.

To determine the potential for the application of energy storage by a utility, the following questions must be answered:

- What is the greatest amount of off-peak energy that could be available for charging energy storage devices?
- What is the distribution of available off-peak energy on a seasonal, weekly, and daily basis?
- What amount of on-peak energy can be supported by the stored energy?
- What type of energy storage devices should be designed for power-system application?

In an attempt to answer these questions, an analysis of the seasonal, weekday, and weekend load shapes using a load-duration programme was done by the Public Service Electric and Gas Company in New Jersey for a number of representative U.S. utilities.[2] The study estimated that, for the U.S. electricity utility industry, the theoretical maximum amount of on-peak energy requirements capable of being supported by the maximum available off-peak energy on a year-round basis is 10 per cent of the total energy produced by the system. For Ontario, no sufficiently detailed assessment has been made. Ontario Hydro has a higher load factor than many U.S. utilities, so the amount of energy available for charging storage devices could be smaller. Trends that could work to reduce the utility's load factor and thus increase available off-peak energy include conservation, solar heating with electricity back-up, and co-generation.

Energy Storage Technologies of Particular Importance

Pumped Storage

Above-Ground Pumped Hydraulic Storage. In a pumped hydro storage scheme, off-peak power is used to operate pumping devices which, in turn, transport water uphill into a reservoir. During peak-demand periods, this water is released and used to generate electricity as in a conventional hydro plant. The concept is similar to that of storing water behind a dam for use during peak-demand periods.

Pumped-storage stations have efficiencies of only about 70 per cent, due to energy losses from the pumping phase in the process. Larger stations tend to be more efficient and have the advantage of economies of scale. Similar to hydroelectric stations, pumped-storage plants have an expected life of 50 years. Construction costs are very site-dependent, ranging from $2 to $10/kW·h stored; operating and maintenance costs are about $1.60/kW per year.[3]

Ontario Hydro currently operates one pumped-storage facility at Niagara Falls and is considering two other schemes. Figure 4.2, taken from Hydro's "Surface Pumped Storage Status Report", shows a proposed location for a pumped-storage facility at Delphi Point. Fig. 4.2: p. 4

Delphi Point is on the Niagara escarpment adjacent to Georgian Bay. Because it is near one of Ontario's largest ski resorts and in a Class One recreational area, approval of a pumped-storage development would probably be difficult to obtain. The possibility of storing between 300 and 2000 MW of off-peak electric power at Delphi Point is nevertheless attractive.

The Matabitchuan Project would most likely involve the use of up to 500 MW of pumping power, available during off-peak periods. Fourbass Lake and Lake Timiskaming would be used as the upper and lower reservoirs, respectively, and would require a "headworks/penstock powerhouse" adjacent to an existing generating station. Its main appeal is that it would take advantage of the existence of a large upper reservoir with some natural inflow.

Underground Pumped Hydraulic Storage. Underground pumped-storage facilities would have capital and operating costs similar to those of conventional above-ground facilities. The environmental impacts associated with underground pumped storage may not be as severe, depending upon the site. Both Ontario Hydro and Atomic Energy of Canada Limited have made a number of studies on this subject. Figure 4.3 provides a schematic diagram of an underground pumped-storage facility. Fig. 4.3: p. 4

Compressed-Air Storage

This technology involves the compression of air into caves or abandoned mine shafts using off-peak electric power. During peak-demand periods the compressed air is released to combust natural gas or light fuel oil in a gas-turbine generating plant. No large-scale compressed-air storage scheme is yet in operation. However, a number of developments are under way. At the compressed-air energy storage facility in Germany, two subterranean salt caverns are used, each with a capacity of about 150,000 m^3. During night-time off-peak demand periods, air is compressed into the caverns to a pressure of approximately 70 atmospheres. The air is then discharged during the daytime to help meet peak demands over a period of 2-3 hours.

Fuel Cells

A substantial amount of research and development is being carried out on fuel cells in the U.S. Fuel cells have been used successfully in the U.S. space programme as spacecraft power plants. The focus of most current studies is to develop cost effective fuel cell power plants for use by utilities and industry and in buildings.

A fuel-cell power plant generally consists of three major subsystems – a fuel processor, a fuel-cell power station, and a power conditioner. The fuel processor converts a conventional utility fuel to hydrogen gas; the fuel-cell power section electrochemically converts hydrogen and oxygen to water, while producing direct-current power; and the power conditioner converts direct-current power to alternating-current power. If either hydrogen or a hydrogen-rich gas such as coal gas is used, the fuel processor can be eliminated.[4]

Fuel-cell power plants may also be used as energy storage devices, storing large quantities of electricity. In this option, off-peak electricity generation provides energy to electrolysis units, which convert water into its elemental components (hydrogen and oxygen). Off-peak electricity can thus be stored in the form of hydrogen fuel until periods of high demand, when the hydrogen fuel is converted back into electric energy by means of a fuel-cell power plant. This type of storage would require only 1 per cent of the land area needed by a conventional pumped hydro storage system.[5] Also, where a market exists, the hydrogen fuel can be used for transportation applications.

Preliminary system studies and feasibility testing have indicated that a regenerative hydrogen-chlorine fuel-cell system would combine the reliability and flexibility of a hydrogen-air fuel cell but with a higher efficiency. In this concept, a solid polymer electrolyte electrochemical unit produces gaseous hydrogen and chlorine during the electrolysis charge mode and consumes gaseous hydrogen and chlorine dissolved in aqueous hydrogen chloride during the discharge mode with an overall electric-to-electric efficiency in excess of 70 per cent.[6]

Among the advantages of fuel-cell power plants are their reduced nitrous oxide and sulphur dioxide emissions, in comparison with combustion machines, and their water-conserving nature. These characteristics generally tend to increase the siting flexibility of fuel-cell systems.

Integrated Energy Systems Using Fuel Cells. Greater efficiency can be achieved with an integrated energy system using a fuel cell. The integrated system extends the on-site heat-recovery concept to include other energy-converting equipment such as heat pumps. In this system configuration, the fuel cell's highly efficient electricity output is used to drive a heat pump in addition to meeting the other electricity requirements of the building. By-product heat from the fuel cell can be used directly for part of the thermal requirements of the building, such as water heating and space heating, as well as to enhance the thermodynamic operation of the heat pump.

Utility Applications of Fuel Cells and Electrolysis. It is difficult to assess the true economic cost of fuel-cell systems. Much depends on the type of fuel supply and the mode in which the fuel cell is operated. Nevertheless, implementation of a fuel-cell programme could ultimately reduce the need for additional transmission facilities. Furthermore, a reduction of reserve capacity could be achieved while off-peak system losses are minimized.

The main dilemma facing the fuel cell concerns the availability and cost of fuel. As the fuel processor contributes about 25 per cent to the capital cost of the power plant, the use of coal gas and hydrogen fuels that would eliminate the fuel-processing requirement is an attractive option. For Ontario, further consideration should be given to the possibility of using off-peak electricity generation to produce hydrogen fuel through electrolysis, which can then be converted back to electricity during peak-demand periods by means of a fuel-cell power plant. The production of hydrogen from electricity using

electrolysis is approximately 70-80 per cent efficient, that is, for every 100 GJ of electricity used to electrolyze water, 70-80 GJ of hydrogen is produced. Of particular importance to the utility is the fact that off-peak power, or electricity produced at remote locations, can be used to produce the hydrogen gas, which can then be transported or stored like natural gas. Electrolysis/fuel-cell systems can be an asset to the development of small-scale hydroelectric or wind-power systems where the problems of transmission and synchronization with the provincial power grid may be constraints. However, the difficulty of handling hydrogen gas safely is still a major constraint.

Battery Storage

One of the most widely used types of energy storage is the rechargeable battery, which converts electrical energy to chemical energy and stores it for a period of time. As previously mentioned, their compatibility with the electric power system and their compactness make batteries one of the most attractive energy storage technologies.

Utility Applications. Large arrays of batteries could be used as a replacement for spinning reserve or to cope with the problem of smoothing the daily load cycle.[7] Another advantage of a battery storage system is the fact that it can be placed anywhere in the utility distribution and transmission system. Of particular significance is its application to technologies that depend on intermittent energy sources that may not always be available when peak demands occur, as is the case with wind turbines and solar electric cells.

An assessment of energy storage systems undertaken in the U.S.[8] identified several types of batteries as suitable for utility applications. These include lead-acid, sodium-sulphur, sodium-chloride, lithium-metal-sulphide, zinc-chloride, and redox. The lead-acid battery, commonly used in automobiles, is the only commercially available type of battery that has been considered for utility application.[9] Lead-acid batteries have been used to power various kinds of industrial equipment, such as fork-lifts, but projected maintenance and materials costs for utility-scale applications tend to make this type less attractive than other types of batteries.

Sodium-sulphur and sodium-chloride batteries incorporate a solid electrolyte (beta-alumina)[10] that eliminates self-discharge and numerous other failure mechanisms that tend to limit the life of conventional lead-acid batteries. While the raw materials for these batteries are relatively inexpensive, processing costs could delay commercialization.

Lithium-metal-sulphide batteries are attractive because they are small and light. However, most of the prototypes designed to date are troubled by lower cell voltage and high costs. One estimate[11] suggests that a 100 MW·h lithium-metal-sulphide unit would weigh about 725 tonnes and occupy about 375 m^2, compared with 3,175 tonnes and 4,645 m^2 for lead-acid. A 1979 programme review released by the National Research Council in Ottawa[12] identified this battery as a major subject of research.

The zinc-chloride battery has also been proposed for load-levelling applications, although most of the research that has gone into this type of battery has resulted from electrical vehicle developments. As with most kinds of batteries, uncertainties include the duration of cycle life and the cost.

Redox batteries, employing a single metal that is stable in aqueous solution at various oxidation levels, appear to be the most promising.[13] However, development of this type of battery is still at an early stage and its true cost and potential is very difficult to assess.

Transportation Applications. The development of battery storage is of particular importance to the transportation sector, which consumes large amounts of non-renewable fossil fuels. Development of the electrical automobile is dependent on the availability of batteries with enough energy and power density to provide adequate range, speed, and acceleration. About 200 cars with advanced lead-acid batteries are expected to be produced in the U.S. in 1980. Advanced batteries proposed for the late 1980s, such as the sodium-sulphur and lithium-metal-sulphide batteries, which operate at temperatures of up to 350°C, suffer from corrosion and internal shorting. These problems will have to be overcome.

Most electrical vehicle designs use flywheels as a storage device during braking. One such design is the Garrett Flywheel car. It is designed for four passengers, weighs 1,160 kg and costs about $5,000. Its operating range is 137 km. Top speed is expected to be 112 km/h, while acceleration is expected to be from 25 to 55 km/h in 10 seconds and from 0 to 30 km/h in 6 seconds. The Garrett vehicle will use a lead-acid battery that can operate in temperatures ranging from -30°C to 50°C. It is conceivable that, with further developments in battery storage technology, electricity could become an important automobile

fuel in the near future. Furthermore, the development of a hybrid-electric car that will use a fossil-fuel engine for short bursts of energy when acceleration is required or when its batteries are exhausted is a distinct possibility. The addition of one million electrical vehicles in the transportation sector in Ontario would have minimal impact on the need for additional electricity capacity requirements, but there would undoubtedly be logistical problems related to the number of these vehicles that could be charged at any one time.

Thermal Energy Storage

A variety of materials can be used to store thermal energy over an extended period of time, including rocks, water, and phase-change compounds. In addition to solar energy applications, there has been some discussion regarding the use of off-peak electric power to charge thermal storage devices. In Hamburg, West Germany, for example, residential thermal storage systems using hot-brick insulated heaters have had a significant effect on the utility's daily winter load curve. These systems involve the off-peak charging of heaters that can be heated up to 200°C, to flatten the daily load curve. The utility controls the heaters and operates them only during off-peak periods, the way some utilities shut off water heaters during peak-demand periods.

While sensible heat storage in rocks or water requires a large temperature differential to achieve high efficiencies, latent heat storage, which operates on the principle of phase change, requires only a small temperature differential and has a much greater heat capacity. Solid-to-liquid phase change is particularly attractive for thermal energy storage. There are a number of suitable materials for this application, including a range of salt hydrates and fatty acids. This type of system has the advantage of being relatively low-cost. An estimate by A.H. Abdelmessih of the University of Toronto suggests that only $100 worth of material should be required to store 1 million BTU using a salt hydride storage system.[14] The storage of thermal energy through the heat of fusion of salt hydrates appears to be relatively close to commercialization. The rolling cylinder heat exchanger developed by the General Electric Company, for example, actually rolls the salt hydrates to avoid the problem of supersaturation or freezing, which to date has been the biggest obstacle to the commercialization of solid-to-liquid phase-change devices.

Summary

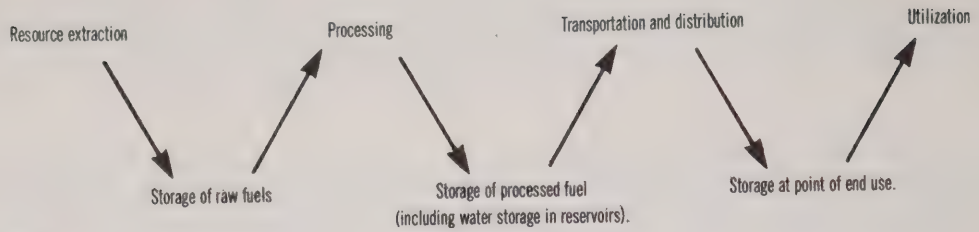
There are a number of energy storage technologies that could alter the patterns of energy utilization in Ontario. Electrification of a larger portion of the transportation sector is a distinct possibility, particularly in light of recent developments in battery storage technology. This will require planning at the utility level to ensure that sufficient generating capacity is available to meet the new demand. However, it is unlikely that the extent of this demand will be significant before the year 2000 and it could be managed by the use of off-peak electricity. Assuming 500,000 electrical cars in Ontario by the year 2000, for example, only 600 MW of off-peak electric power capacity would be required for charging.

Thermal energy storage systems charged by electricity have similar potential to use off-peak power. Thermal storage is integral to most solar heating system designs and it is possible that off-peak electrical heating units controlled by the utility could become an auxiliary option in some situations. However, it is unlikely that new generating capacity will be required to meet this demand.

Combined fuel-cell electrolysis systems could reduce off-peak electric power losses that might result from an expanding nuclear base-load programme coupled with lower rates of electricity growth. The development of this energy storage option would depend on the availability of inexpensive off-peak electricity.

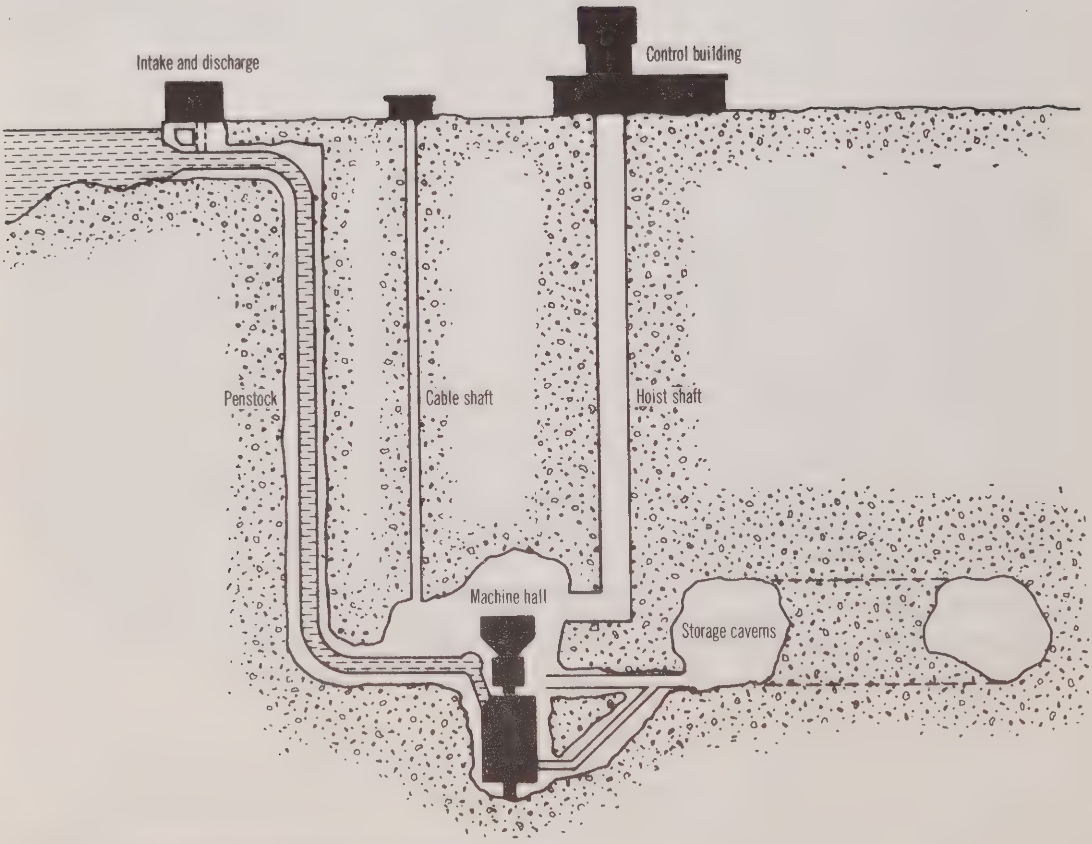
Pumped-storage schemes operated by the utility largely to control daily load variations have limited potential in Ontario due to the lack of suitable sites. The Delphi Point scheme could provide up to 2,000 MW of storage but land approvals could be very difficult to obtain.

Figure 4.1 Points at Which Energy Storage Can Occur in a Typical Fuel Cycle



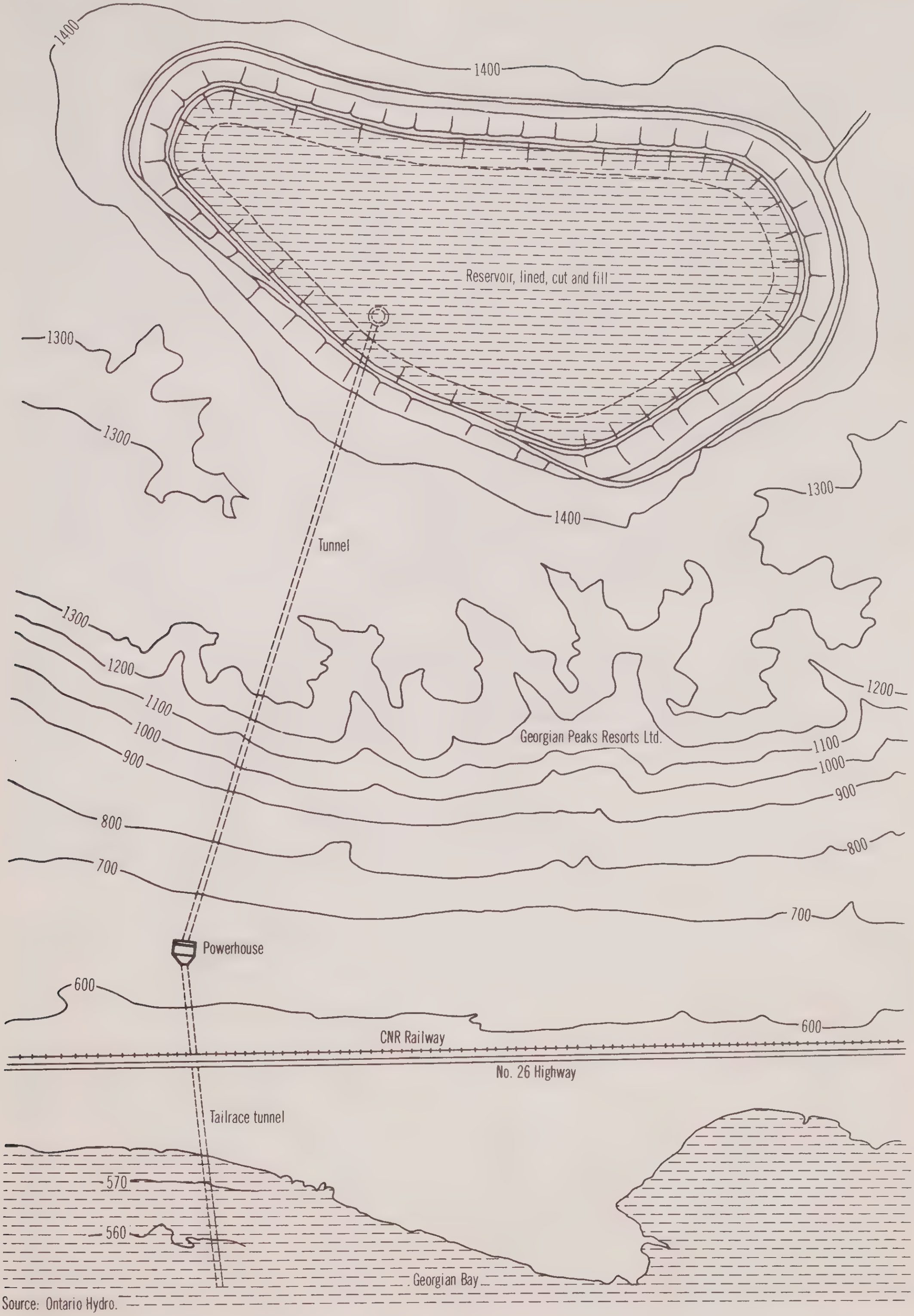
Source: RCEPP.

Figure 4.3 Underground Pumped Storage



Source: "Preliminary Study of Energy Storage Alternatives", Ontario Hydro, January 1975.

Figure 4.2 Delphi Point Pumped Generating Storage — Conceptual Layout



Source: Ontario Hydro.

CHAPTER FIVE

Improving the Efficiency of the Electric Power System

A number of technologies are available that can improve the efficiency of primary resource utilization in electricity production. These include load management, district heating, and co-generation.

Load Management

Load management includes any technique whose application tends to level the demand on a system in order to increase the capacity factors of its more efficient generating units, and to reduce the required peak capacity. Load management is beneficial when the total cost of generation to meet peaking loads, less the total cost of generation to meet base-load demand, is greater than the total cost of load management. It is particularly advantageous when the high-capital-cost/low-operating-cost capacity in the system is being operated at low capacity factors. This may well occur in the Ontario Hydro system by 1987, when there will be 17,000 MW of nuclear and base-load power in the system, if electricity demand grows at a slower rate than the 4.5 per cent average annual growth the utility is forecasting, to the year 2000.

Methods of shifting loads from the peak periods to the night-time valleys include time-of-day pricing rate structures; segregation of industrial loads into interruptible and non-interruptible loads (industries could also be encouraged to have on-site storage); control of some industry loads by the utility; and control of some residential and commercial loads by the utility. At present, municipal utilities in Ontario control about 150 MW of water-heating load whereby the load can be shut off for 1-1/2 to 2 hours at times of peak demand. This generally does not affect the customers because of the storage capacity of the hot-water tanks. Larger tanks of 450-500 L could store enough heat to make 8-hour shut-downs feasible. With a 1979 residential water-heating load of 1,100 MW in Ontario, this would be significant. Other appliances and/or space heating could be similarly controlled but with more of an impact on consumer life-style.

Control of customer loads can be achieved by the use of various means that are available to shut down appliances or equipment. Examples include a power-line carrier or ripple control device that sends a pulsed and coded signal through the transmission system; a telephone system control whereby a signal is transmitted over a telephone line; an AM radio signal sent with the regular programming of an AM station and picked up by an AM receiver that activates a switch; a VHF radio control, similar to the AM control but requiring a dedicated transmitter; and a cable TV control whereby the control signal is sent via the cable TV network.

Ontario Hydro's forecasts of load-management potential in its report No. ECD-78-6, developed by its Load Management Department, are based on the 1978 load forecast of 5.1 per cent per annum rate of growth of electricity demand between 1978 and 2000 and are shown in Table 5.1. Due to uncertainty

Table 5.1 Potential for Managed Loads by Sector

	Managed load (MW)		
Year	8-hour	16-hour	Total
Residential Market			
1980	200	0	200
1987	500	400	900
1997	1,000	900	1,900
2007	1,100	1,800	2,900
Commercial Market			
1980	0	0	0
1987	400	0	400
1997	900	0	900
2007	1,400	0	1,400
Industrial Market			
1980	100	300	400
1987	200	200	400
1997	300	300	600
2007	500	500	1,000

Source: Ontario Hydro, Report ECD-78-6, July 1978.

regarding the impact of load-management techniques on the bulk power system, Ontario Hydro has chosen a load-management target of 50 per cent of the maximum peak-demand reduction. It is important to note that, for a system that will have only a 3.5 per cent per annum growth between 1976 and 2000, the maximum potential would have to be reduced proportionately.

District Heating

The term district heating refers to the commercial supply of steam or hot water for heating purposes. At present, there are only four true district heating systems in Canada. These are in Vancouver, Winnipeg, London, and Toronto, and all were developed to supply heat to large commercial buildings in the downtown business districts. There are essentially three components to a district heating system: the generating source, the distribution system, and the user.

The generating source for a district heating system can be an electric power generating facility that distributes by-product steam or hot water via a network of supply-and-return flow pipes arranged in parallel. The generating source may be a facility designed expressly for the purpose of supplying this steam or hot water. In Europe, it is common to build a new suburban community complete with a district heating distribution system; a portable-package heating plant is erected on vacant land and connected to the steam or hot-water distribution system. The appeal of these portable-package units lies partly in their transportability; they are well suited for use in remote settlements or locations where the building of a stationary power plant would be too expensive.

For most district heating systems, underground insulated water or steam distribution systems are preferred, primarily because the ground acts as an insulator, reducing energy losses. Several types of insulated underground piping are available for district heating systems. However, underground pipes tend to spring leaks as a result of frost heave and the movement of heavy equipment on the surface. Underground pipes are difficult to service, but leaks can be located by the use of a technique called thermography.

A unique approach, suggested in a study by Energy, Mines and Resources, is the use of the municipal water supply system as the distribution system for a district heating scheme.[1] In this system, heat pumps installed in residential dwellings would serve as heat exchangers, transferring heat from the supply of warmed water to the air within a dwelling.

The equipment that belongs to a district heating customer and forms the interface between the district heating distribution system, on the one hand, and the building heating system, on the other hand, is commonly referred to as subscriber equipment. In a warm-air heating system, the subscriber equipment will take the place of the warm-air furnace; with a hot-water heating system the subscriber equipment will take the place of the hot-water boiler. For domestic hot-water heating, the subscriber equipment takes the place of the usual electrical or gas-fired hot-water storage heater. In all cases, this equipment includes a heat-metering or flow-metering device, a heat exchanger, piping and associated valves, fittings, controls, and wiring. In Europe, packaged units known as subscriber centrals are in wide use. They include all of these components in sizes suitable for single residences or apartment units. For larger buildings, commercial-size components are often pre-assembled or made up of several modular components. These units follow the general trend towards factory fabrication rather than on-site assembly.

Nuclear Power and District Heating

With the high front-end capital costs of nuclear power generating stations and the associated requirement to produce electricity at high capacity factors, it is reasonable to consider the possibility of utilizing the low-grade heat that is a by-product of the electricity generating process and represents 60-70 per cent of the initial energy content of the fuel. Furthermore, by supplying the seasonally fluctuating part of the utility's load (i.e., electrical space heating) in a way that improves primary energy utilization, total installed capacity can be reduced. In this respect, district heating offers the additional advantage of capacity management. An AECL study[2] discusses this important characteristic. It examines an all-nuclear electricity supply scenario (excluding transport), in which one-third of the energy end use is for power and light, one-third is for seasonally invariable thermal applications and one-third is for seasonally variable applications. In this scenario, total primary installed capacity is approximately three times the end-use energy. However, if all of the thermal load is supplied directly via district heating, with an overall energy utilization three times that of electrical resistance heating,

then the installed primary thermal capacity required for thermal applications is correspondingly reduced.

At present, CANDU stations operated by Ontario Hydro convert 29 per cent of their thermal energy to electricity while the remaining energy is discarded as waste heat. In a district heating scheme, the temperature of the heat discharge would have to be higher than at present, and, although this would result in more useful energy, less electricity would be produced. It is anticipated that a CANDU-based district heating scheme would probably produce electricity at an efficiency of 20 per cent, while 40 per cent of the energy potential would be at a high enough temperature for space-heating applications. For Ontario Hydro's current approved nuclear commitment of 13,800 MW by 1990, this would imply a reduction of electricity output by approximately 4,200 MW but with a corresponding thermal output of approximately 17,000 MW, which could be available for district heating applications. Assuming an average household peak demand of 20 kW, this would be enough energy to heat 850,000 households.[3]

The study of district heating prepared by Acres Shawinigan Ltd. for the Ontario Ministry of Energy (February 1976) and numerous other subsequent studies agree that district heating using nuclear power stations has obvious long-term economic advantages, particularly where new industrial or residential subdivisions are being planned nearby. In the case of the North Pickering community, a number of more detailed analyses are being carried out.

The St. Lawrence Housing Project, City of Toronto

Another proposal for the use of district heating is presented in the Energy Feasibility Study for Phase B of the St. Lawrence project, prepared for the City of Toronto by the ECB Group.[4] The study recommends that the heating system for the development be of the hydraulic type, which would permit connection to a future central heating plant or district heating system, without major retrofit. The study suggests that energy reclaimed from the Commissioners Road incinerator could be used to supply the development. Similarly, a gas-fired hot-water central-heating plant could be constructed to provide the heating requirement. The study also examines the possibility of incorporating the Richard L. Hearn Generating Station into the district heating scheme but concludes that, because of its 'peaking' nature, this option would not be optimal. However, although the useful life of the steam generating equipment in the plant is not expected to extend much beyond the year 1990, this situation would change if the Hearn station were retrofitted with new steam – and electricity-producing equipment and operated at a higher capacity factor.

Although there is some uncertainty as to the most appropriate energy supply system for the St. Lawrence project, it is widely accepted that energy conservation must play a key role. The study concludes that an energy budget of 18 kW·h per square foot per year is readily achievable and should be set as a target for the construction of Phase B. The study also suggests that thermal insulation in buildings be upgraded in accordance with the requirements of the Measures for Energy Conservation in Buildings issued by the National Research Council.

District Heating and Agriculture

The Ontario Energy Corporation has undertaken to develop two test greenhouse facilities, one at Pickering and another at Douglas Point, in an attempt to explore the feasibility of using by-product heat from Ontario Hydro's nuclear power generating facilities in those areas. If preliminary tests prove to be successful, an 8-acre commercial greenhouse project is proposed for the Pickering site and a 100-acre "AgriPark" complex for Bruce County.

Co-generation

Industries that produce a large amount of process-steam, such as the pulp and paper and chemical industries, can generate electricity by expanding this process-steam through a turbine and driving an electrical generator. The low-pressure exhaust from the steam turbine can be used as process-steam while medium-pressure requirements can be satisfied by steam extracted part way through the turbine. The electrical output from this type of process is essentially limited by the steam requirements of the particular industry. The following summary, taken from an EPRI document, lists some of the many advantages of co-generation.

Advantages to the Utility

Reduced fuel cost – 30-60 per cent

Reduced capital cost
– less costly equipment
– no site acquisition
– no transmission line
Higher availability
Incremental equipment acquisition
Equipment available faster
Reduced environmentalist problems
Increased reliability
Increased revenue
More than 5,000,000 hours of operational experience

Advantages to the Customer
Free stand-by power
Stand-by power on line

Advantages to the Country
Greatly reduced fuel consumption

In 1977, thermal generation capability owned by industrial concerns in Ontario totalled 510 MW.[5] Such facilities include the Dow Chemical gas-turbine, steam, combined-cycle system at Sarnia and the Great Lakes Paper operation at Thunder Bay. Ontario Hydro has co-operated in the development of co-generation to the extent of providing a special stand-by rate for industrial firms generating their own power. Hydro has yet to become involved in systems where the turbine generator or part of it is owned by the utility, although the possibilities of a separate utility entering into joint ventures with industrial firms for co-generation plants are now being explored.[6]

The concept of an industrial complex built around a combined power and process-steam plant has a number of energy conservation possibilities. Integration of a group of industries could provide the economy of scale necessary to justify the construction of new generating facilities. In addition, such a configuration would facilitate the utilization of the waste heat normally lost in the various industrial and power production processes.

Because generation and utilization take place on site, the installed cost of a co-generation plant does not necessarily involve the cost of transmission. When transmission losses associated with central power generation are taken into account, the efficiency of co-generation is approximately double that of a central facility.

Figure 5.1, taken from a presentation by the Garrett Corporation to the Dual Energy Systems Workshop conducted by the Electric Power Research Institute in September 1977, provides a general overview of the cost and potential savings of co-generation. Fig. 5.1: p. 52

For example, assuming that a customer has a requirement for 3,850 kW and 33 GJ (31 million BTU) per hour, he would probably buy electricity from the electric power utility and his heating fuel from an oil or gas company. The 3,850 kW would require an input of approximately 47 GJ (45 million BTU) per hour of primary energy; this, combined with the 33 GJ per hour of direct thermal load, equals a total of 80 GJ (76 million BTU) per hour. If, however, the customer were to install a generator producing the 3,850 kW and 33 GJ per hour simultaneously, the total primary energy requirement would be only 52 GJ (49 million BTU) per hour. This would represent an energy saving of 35 per cent. Whether utility- or industry-owned, the market for low-grade heat should be considered when new thermal generation possibilities are being explored. In northern Ontario, for example, the Atikokan facility might better be located at Kenora, where there would be a market for low-grade heat. In the pulp and paper industry, a number of possibilities exist, many of which have already been demonstrated. Most of the pulp and paper mills in British Columbia, for example, generate power as a by-product of process-steam, using bark or other forest residue.

In Ontario, the present estimated potential for co-generation from wood wastes is approximately 300 MW.[7] Table 5.2 indicates the total estimated potential for co-generation from wood wastes in Ontario's pulp and paper industry. In addition, about 50-100 MW of co-generation in the pulp and paper industry is attainable from other fuels. Of the total industry co-generation potential of 350-400 MW, about 50 MW could be sold to the electric power utility as surplus. While this potential exists, only a few projects are being pursued seriously. In Espanola, the E. B. Eddy Company is already generating 17 MW from co-generation facilities. In North Bay, problems with a municipal refuse dump near an airport runway

make the combusting of municipal waste to raise steam for electricity production attractive. The Ministry of Energy is studying plans for a generating facility that would use municipal refuse and wood waste from Nordfibre Ltd.[8]

Table 5.2 Potential for Co-generation from Wood Wastes in the Pulp and Paper Industry

Place	Company	Steam (pounds)	Potential (MW)
Cornwall	Domtar	580,000	34.8
Espanola	E. B. Eddy	600,000	36
Fort Frances	Ontario-Minnesota	385,000	22
Hawkesbury	Canadian International Paper	200,000	10
Huntsville	Kimberly Clark	120,000	7.2
Kenora	Ontario-Minnesota	420,000	25.2
North Bay	Nordfibre	100,000	6
Red Rock	Domtar	430,000	25.8
Sault Ste. Marie	Abitibi	270,000	16.2
Sturgeon Falls	Abitibi	195,000	11.7
Terraca Bay	Kimberly-Clark	350,000	21
Thorold	Abitibi	200,000	12
Thorold	Georgia Pacific	140,000	8.4
Thunder Bay	Abitibi	225,000	13.5
Thunder Bay	Abitibi	285,000	17.1
Thunder Bay	Abitibi	250,000	15
Total			282

Source: "Lockwood's Directory", Vance Publishing Corporation, New York, 1978.

The Leighton and Kidd "Report on Industrial By-Product Power"[9], suggested that, if all process steam installations in the province were modified or re-built to produce by-product power, 3,000 MW of co-generation would be attainable. Assuming a 5 per cent growth in steam consumption, the report suggests that this could be increased to a potential of 4,400 MW by 1985. However, with existing physical, institutional, and economic constraints, it is likely that only about 20 per cent of this total potential is realizable by 1985. In fact, Ontario Hydro, in conjunction with the Ministry of Energy, has already identified a potential for 700-800 MW of co-generation in Ontario by the mid 1980s, based on 43 operations with steam-producing capability of at least 100,000 pounds per hour. Beyond the mid 1980s, this potential could grow as the steam requirements increase for existing facilities and as new industries begin operation. The factors that will influence the penetration of co-generation are discussed in more detail in Volume 5 of this Report. Three possible scenarios are reviewed, ranging from 400 MW to 2,280 MW of potential co-generation capacity installed between 1980 and the year 2000 with varying assumptions regarding fuel prices and discount rates.

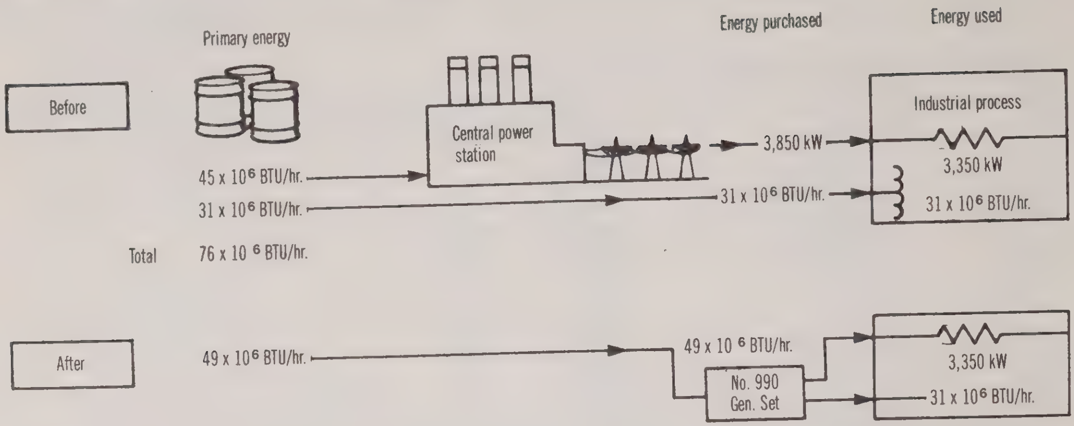
Summary

The development of technologies that improve the efficiency of energy utilization should be a priority for Ontario. Co-generation is an important option, particularly in locations where wood or municipal wastes can be used as a fuel. In addition, where an industrial process-steam market exists, co-generation can provide an attractive alternative to conventional utility-operated thermal generating stations. The extent of Ontario's co-generation potential will be determined largely by relative fuel prices. Up to 3,000 MW of co-generation could conceivably be installed between 1980 and 2000.

District heating schemes can also greatly improve the efficiency of energy use, but require considerable capital expenditure, especially where community infrastuctures already exist. There are, however, other markets for low-grade heat, such as greenhouses and aquaculture, that should be considered when new thermal generation facilities are being planned.

Like energy storage devices, load management devices are particularly attractive when high-capital cost/low-operating-cost base-load capacity in the electric power system is being operated at low capacity factors as could be the case in the Ontario Hydro system by 1987.

Figure 5.1 An Example of the Energy Savings Resulting from Co-Generation



Savings

27×10^6 BTU/hr., or 35% of previous primary energy input.

NOTE: Assumes installation of a Garrett No. 990 Generator Set.

Source: The Garrett Corporation.

CHAPTER SIX

Energy Conservation – An Alternative to the Increasing of Energy Supply

Conservation is something everyone can take part in. It implies wise and efficient supply and use of energy resources; but beyond a certain level it may require the refitting of technology to eliminate some of the built-in inefficiencies of the energy infrastructure that arose largely during times of energy abundance.

Predictions concerning the impact of energy conservation practices on energy demand vary, largely because of the difficulty of changing life-styles and the uncertainty of the cost of conservation measures compared with the cost of increasing the energy supply. Furthermore, the theoretical performance of conservation devices does not always correspond to actual experience with those devices.

The Commission's issue paper on the demand for electric power points out that "fundamentally, the need for energy by an organism, by man, and by society is based on two factors: the energy needed for growth and the energy needed for maintenance". There is no question that energy demands have tended to grow in step with the population and the economy. Furthermore, in the last two decades there has been a continued proliferation of energy infrastructure, to the point that significant quantities of energy are required simply to maintain the delivery system. However, it would be unrealistic to view an immediate and radical change in Canada's energy systems as a solution to our energy problem. In fact, it would require an even greater energy investment than is now being made to initiate a change-over from an oil-consuming economy, for example, to a solar-based one. In the longer term, though, as society begins to replace the existing infrastructure and as conventional fuels become increasingly expensive, such a change-over may slowly occur. Thus, conservation has an important role to play – first, in the promotion of energy savings and, second, in the buying of time for the gradual implementation of new energy forms. Within the parameters of this "refitting", there is a great potential for conservation in Canadian industry. Contrary to the notion that conservation would result in severe economic upheaval, it is more likely that the variety of new processes and procedures associated with it will lead to a flurry of economic activity. Quite simply, as rising energy prices produce more efficient utilization, technology will be adapted to counteract the impinging constraint. The speed with which this adaptation occurs will depend on the planning and preparation that have been undertaken, particularly in the areas of materials research, new-product development, and new coercive legislation.

Recent Efforts towards Energy Conservation

A number of programmes aimed at energy conservation have been initiated by all levels of government and industry. In government, perhaps the most visible programme is that of the Office of Energy Conservation (O.E.C.), a branch of the Department of Energy, Mines and Resources. OEC has initiated a number of programmes aimed directly at the public with the express intent of increasing awareness of energy issues. The Canadian Home Insulation Program (CHIP) offers home-owners an opportunity to upgrade their insulation with a certain amount of government financial assistance. OEC also helped to bring about the decision to reduce the highway speed limit from 70 mph to 60 mph (100 km/h). In addition, both the federal and provincial governments have eliminated their sales tax on certain energy-conserving equipment.

Standards and Codes

Implementation of energy conservation programmes beyond those of a voluntary nature will require a certain amount of regulation through standards and codes. This will necessitate more accurate targeting of energy utilization levels in all sectors. For example, in the transportation sector, although fuel prices will tend to favour more fuel-efficient vehicles, the response of the automobile manufacturing industry to both rapidly escalating fuel prices and the need for emission controls can be accelerated by standards legislation, as experience has shown. In the building and construction industry, standards have brought about a significant reduction in the incidence of fires. Similarly, energy standards can assist in the reduction of a significant amount of heat loss and air infiltration through the building

membrane by requiring improved design, materials, and construction techniques. For both the automobile and the construction industries, target energy utilization levels are essential for the development of realistic standards and codes.

An example of energy conservation guidelines is contained in the "Measures for Energy Conservation in New Buildings" developed by the National Research Council (NRC). The measures specify the performance requirements for the various components that must be incorporated into the design of a new building, but they do not dictate how the design must be executed to meet the requirement. It is recognized that certain requirements, especially those for mechanical and lighting systems, will restrict the use of some present-day design practices, but that there are alternative approaches that are less energy-intensive and will meet the design objective.

According to the NRC's commentary that accompanies the measures:

> Designing and constructing a building to the requirements contained in the "Measures" will result in a building which is capable of being operated in an energy conserving manner, but the full savings will result only if the building is operated properly, and if the mechanical and electrical systems and equipment are maintained in efficient operating condition.[1]

Clearly, the NRC measures are intended to permit a flexible approach to the implementation of conservation practices in new building design. However, from the standpoint of provincial and municipal planning, it may be desirable to legislate more stringent energy standards in order to protect against longer-term uncertainties.

Thermographic Analysis

One method that can be used to evaluate relative heat loss emitted through the roof of a building is aerial thermography, in which an infrared scan is recorded on photographs that are then analysed for temperature variations. The Ontario Ministry of Energy is promoting a programme using aerial thermography to evaluate the condition of attic insulation in residential buildings.

The interpretation of a thermogram can often be quite complicated because information about the building form is essential to an accurate evaluation of the heat loss. Experience has shown that residential buildings pose more problems of interpretation than industrial sites because of their varied size and shape. As a result, research is being conducted to assess the performance standards related to heat loss in different types and forms of buildings. This work is divided into two areas – industrial sites and residential buildings. The industrial assessment has been completed, and it has concluded that aerial thermograms can identify excessive heat loss at most flat-top industrial sites. Research on sloping-roof residential buildings is being undertaken by the Ontario Centre for Remote Sensing (OCRS), and preliminary results indicate that heat loss from a residential unit is greatly dependent upon the number of floors and the configuration of the building.

Data interpretation work is also being conducted by OCRS to develop informative presentation techniques for the community. In May 1977 the town of Lindsay organized a community insulation clinic to acquaint home-owners with the results obtained from the aerial thermograms of the town taken during the previous winter, and to advise residents whether their attic insulation should be increased. This pilot programme proved successful and the OCRS is now developing a prototype presentation for other Ontario communities.

A few, as yet unpublished, conclusions have emerged from aerial thermography concerning the heat-loss parameters in two-storey and single-storey dwellings. For example, a two-storey dwelling (with family room, living room, and kitchen on the ground floor and bedrooms on the upper level) with the thermostat on the ground floor loses more heat than an average one-storey dwelling. This may be attributed to the problem of temperature fluctuation on the ground floor when exterior doors are opened, since more heat is then required to regulate the temperature on the ground floor. As cold air rushes in, the displaced heat naturally rises to the upper floor causing a greater concentration of heat on the second floor; this heat then permeates the ceiling and escapes through the attic insulation.

Another way to assess heat loss is through ground-based thermography involving an on-site analysis in which portable infrared equipment is used to scan exterior walls and floors. In general, the interpretation of heat loss characteristics is more complete, and the technique can be used to identify inadequate insulation levels or poor building construction. There are a number of private companies that will do the analysis on a building and then recommend the appropriate measures to increase energy conservation.

In addition to residential applications, thermography has numerous industrial uses, such as identifying "hot spots" in electrical distribution systems, broken steam lines, and heat loss in production processes.

Some Other Initiatives

The various levels of government are working in many other ways on energy conservation. Less visible, but of equal importance, are the efforts by industry and the commercial sector, often in consultation with the energy utilities, to conserve or optimize the utilization of energy. For example, in Canadian Tire Corporation stores in Kingston and Milton, the lighting load was cut by 50 per cent with a reduction in lighting level of only 33 per cent. Contrary to the fears that have been expressed by many retailers, neither the number of customers nor the sales level was affected by the reduction.

Other conservation measures introduced by the stores included reducing the period of lighting, lowering hallway heating levels to 10°C, reducing hot-water supply temperature, and reducing compressor pressure. The Kingston store saved 515,970 kW·h in 1977, or 27 per cent of its 1976 electricity consumption. The smaller Milton store saved 39,000 kW·h, or 24 per cent of its 1976 consumption.[2]

In another example, at the McKellar General Hospital in Thunder Bay, a $5,000 investment in energy conservation in 1976 resulted in first-year savings of $36,000. Lighting levels in non-patient areas were reduced by 40 or 50 per cent by switching off or removing alternate rows of lights, replacing existing bulbs with lower-wattage bulbs, and using individual switches for lights. In addition, the use of air conditioning was reduced; kitchen equipment such as ranges, ovens, and dishwashers were shut off when not in use; and steps were taken to improve efficiency in the use of the pneumatic tube system, the chiller unit, the power plant, the incinerator, and the laundry. Savings from 1975/76 to 1976/77 were 840,000 kW·h, or about 15 per cent of the previous year's consumption.[3]

In 1976, Ryerson Polytechnical Institute instituted an energy conservation programme at Jorgenson Hall that resulted in a 45 per cent reduction in energy consumption. This ambitious programme was begun in 1973 when some operational conservation measures were instituted, including: reducing lighting, eliminating snow-melting, reducing building temperatures in winter and raising them in summer, and shutting down the ventilation system during the night. In 1976, the programme was expanded. Jorgenson Hall's refrigeration units were used to provide cooling for other campus buildings and an existing under-utilized steam-heating plant was used to provide heat for the building at a cost far below that for electric heating. In four years the programme resulted in an annual saving of $418,000, with a reduction in electric energy utilization of 28 GW·h, bringing annual use down to 60 per cent of previous levels.[4]

Estimates of Energy Conservation Potential in Ontario

Residential Sector

Home Insulation. With the exception of the transportation sector, the potential for energy conservation is perhaps greatest in the residential home-heating market. Residential space heating accounts for 15 per cent of Ontario's total energy consumption, and transportation accounts for 28 per cent; it is easy to understand why these two areas have been the main target of government conservation efforts to date.

In the Canadian climate there is no question that strict insulation standards and certain basic design principles should be incorporated into new buildings. Some of these include: orientation of the building towards the south, north-side shelter, double-pane glass with insulated shutters, and increased insulation levels throughout the building. However, there are economic limits to the amount of energy conservation that can be justified in a dwelling unit. Triple-glazed windows, for example, do not provide an energy advantage when the cost of producing the additional glazing is considered, except in severe climates.[5] Also, with today's building construction practices, there are definite limits to the advantages of insulation beyond a certain point. The economics of increasing insulation levels is discussed extensively in Volume 5 of this Report.

One estimate[6] suggests that a 40 per cent reduction in energy consumption for residential home heating can be achieved by improvements on both the new and existing housing stock. Dr. David Brooks, in a presentation to the Legislative Assembly of Prince Edward Island in 1976, suggested that, if serious conservation measures were instituted for residential buildings, the energy required for space heating by the year 1990 would be less than what we consume now for the same end use.[7]

Some recent experience supports the idea that considerable reductions in energy consumption can be achieved through integrated energy-efficient building design coupled with higher insulation levels. The Saskatchewan Conservation House, which opened in January 1978, incorporates insulation levels of R60 in the ceiling, R40 in the walls, and R30 in the floors.[8] Most of the windows are on the south side of the house to take advantage of passive solar heat, and they are designed with insulated shutters (R22) to reduce heat loss during the night and on cloudy days. The two-storey house has a combined floor area of 1,835 square feet (approximately 166 m^2) and does not have a basement (see Figure 6.1). Fig. 6.1: p. 6

The key elements to the Conservation House are:

- a modified wood frame construction to provide foot-thick double walls to accommodate R40 insulation
- an air-to-air heat exchange system to recover 70 per cent of the heat from exhausted air
- insulated shutters for windows
- a carefully applied vapour barrier.

With these devices, the Conservation House requires only a single 3 kW heater, which is sufficient to heat the house even when the outside temperature is -35°C. The cost of heating the house during the 1978-9 winter heating season was only about $100.

The total cost of building the Conservation House was $130,000 over two years, of which $50,000-60,000 was for construction costs and $70,000-80,000 was for the active solar system, development fees, architectural fees, monitoring, and maintenance. A Regina builder, Enercon Building Corporation, has already begun incorporating many of the energy-saving features of the Conservation House into new houses for a package price of $3,500, and he claims that a 1,500-square-foot (140 m^2) house can be electrically heated for only $150 per year.[9] This is a saving of at least $350 a year based on present rates for electricity.

Table 6.1 illustrates how super-insulation levels can reduce the energy consumption of a typical family dwelling in Ontario. On the basis of fuel costs of $3.00/million BTU for natural gas and $0.03/kW·h for electricity, the annual energy savings of 67 GJ (63 million BTU) that are achieved through super-insulation levels translate into a saving of $315 per year for a home heated with natural gas and $554 per year for an electrically heated home. Table 6.2 outlines the assumptions that are used in making these estimates of potential fuel savings.

Table 6.1 An Example of the Energy Saving Made Possible in a Typical Single-Family Detached Home by Increasing Insulation Levels

	Amount of insulation assumed					
	Attic 750 sq. ft. (70 m^2)	Walls 1,500 sq. ft. (139 m^2)	Basement 750 sq. ft. (70 m^2)	Windows 200 sq. ft. (19 m^2)	Number of air changes/hour 100,000 cu. ft. (283 m^3)	Annual heat losses for a home situated in a 7,000°F (4,000°C) day zone
Super-insulation level					0.25	
Imperial units	R60	R40	R30	R2		25 million BTU
Metric units	R10.5	R7	R5.3	R0.35		26 GJ
Low-insulation level					1.00	
Imperial units	R10	R12	R5	R2		88 million BTU
Metric units	R1.75	R2.1	R0.9	R0.35		93 GJ
Energy saving						63 million BTU (67 GJ)

Source: RCEPP.

Table 6.2 Annual Dollar Saving and Pay-back Periods Resulting from Super-Insulation Levels in a Natural-Gas-Heated Home and an Electrically Heated Home

	Natural gas heating	Electrical resistance heating
Annual dollar saving from reduced energy consumption	$315	$554
Insulation and heat exchanger investment	$5,100	$5,100
Rate of return on investment per annum	6.2%	10.9%
Pay-back period	16.2 years	9.2 years

Assumptions:

1. Annual energy saving relative to low-insulation case (from Table 6.1): 63 million BTU (67 GJ)
2. Cost of natural gas at point of end use: $3.00/million BTU ($3.17/GJ)
3. Cost of electricity at point of end use: $0.03/kW·h
4. Cost of insulation in the ceiling: $0.017/square foot/R (imperial); $1.00/$m^2$/R (metric)
5. Cost of insulation in walls and basement: $0.065/square foot/R (imperial); $4.00/$m^2$/R (metric)

6. Cost of heat exchanger: \$500
7. Efficiency of natural gas conversion at point of end use: 60 per cent
8. Efficiency of electricity conversion at point of end use: 100 per cent
Source: RCEPP.

If insulation expenditures are viewed as a long-term investment, levels of twice those currently installed in a typical house would be economic. As previously mentioned, a detailed treatment of the advantages of investing in higher insulation levels is contained in Volume 5 of this Report, which suggests that the feasible secondary energy savings for new Ontario homes with higher insulation levels and improved air infiltration control are 79,000 TJ for an investment of \$1.8 billion, or \$1.36/GJ For insulation levels contained in the Ontario Building Code, a \$1.3 billion investment would save 45,000 TJ for a unit energy cost of \$1.66/GJ.[10] The most attractive alternative energy supply options require double this investment, or about \$3/GJ, while new electrical generating facilities operating with a 30 per cent capacity factor require seven times the investment per unit of energy.

Appliances. A number of efficiency improvements are expected to contribute to the reduction of energy consumption of residential appliances. Some of these include: increased insulation for hot-water tanks, refrigerators, and ovens; the use of microwave ovens; and the use of more efficient lighting. It is also anticipated, however, that the trend towards increasing saturation in the acquisition of existing types of appliances and the introduction of new ones will reduce the potential savings during the 1980-2000 time frame. Table 6.3 indicates that a reduction of approximately 7 GJ annually per household can be achieved by the year 2000, based on a number of possible efficiency improvements.

Table 6.3 Energy Saving per Household in Appliance Utilization Possible through Certain Efficiency Improvement Measures

Measures	Present use (GJ)	Use in 2000 (GJ)
Water heating – increased insulation; point-of-use heating	25	20
Cooking – use of microwave ovens for 50 per cent of cooking	4	3
Refrigerator – increase efficiency to USFEA 1980 standard	4	2.8
Air conditioning – doubling of saturation level; rise in efficiency to USFEA 1980 standard	2	3
Freezers – rise in efficiency to USFEA 1980 standard	1.6	1.2
Lights – more fluorescent lighting	2.6	1.3
Other uses – rise in efficiency to USFEA 1980 standard; doubling of saturation level	1.2	2.1
Total	40.4	33.4

Source: Based on USFEA standards for appliances by 1980. Present applicance energy use is taken from "The Conservation of Energy in Housing", Central Mortgage and Housing Corporation, 1977.

Combined Potential Savings. The time lag, characteristic of any programme requiring front-end capital input on the part of the average consumer, must be taken into account in estimating the combined energy savings that could be achieved through conservation in the residential sector by the year 2000. Although super-insulation levels in residential dwellings would result in substantial fuel savings, the measures recommended in the National Research Council's guidelines are more representative of what is likely to occur. As shown in Table 6.4, houses built to the NRC guidelines of R28 in the ceiling, R12 in the walls, and R10 in the basement could have unit space-heating requirements of as little as 60 GJ per heating season, while the existing stock could be retrofitted to reduce heat loss to an average of 120 GJ

Table 6.4 Residential Sector Energy Use in Ontario, 1975-2000

		Energy use per household (GJ)			
	Number of units	Space heating	Other purposes	Total	Total energy use (TJ)
1975					
Apartments	772,000	39	43	82	63,300
Non-apartments	1,768,000	170	43	213	376,600
Total	2,540,000				440,000
2000[a]					
Apartments	1,000,000	39	33.4	70.4	70,000
Non-apartments (existing)	2,150,000	120	33.4	153.4	330,000
Non-apartments (new)	850,000	60	33.4	93.4	80,000
Total	4,000,000				480,000

Note a) Assumes implementation of the conservation measures indicated in Table 6.3 and higher insulation levels for new and existing non-apartment dwellings.
Source: Based on Statistics Canada, "Household Facilities and Equipment", Report 64-202. May 1978.

per heating season. As previously mentioned, energy use for existing types of appliances could be reduced from over 40 GJ to about 33 GJ annually per household. With these efficiency improvements in residential energy use, it is likely that total energy use will grow to only 40,000 TJ by the year 2000, even with an increase of about 1.5 million in the number of new homes. This represents a growth rate of only 0.16 per cent per annum in residential energy use from 1980 to the year 2000. The extent to which electricity use will grow in this sector will largely depend on the penetration of electric space heating and water heating, in comparison with natural gas and other forms of heating.

Commercial Sector

Present commercial space in Ontario is roughly 157 million m^2,[11] while energy consumption is about 1,800 MJ/m^2 per year, or 285,000 TJ/year. The Ontario Ministry of Energy forecasts a 2.5 per cent per annum growth in the amount of commercial floor space from 1975-2000, which would result in a total of 293 million m^2 by the year 2000. Current operating experience suggests that existing buildings can be operated at reduced energy intensities of 1,450 MJ/m^2 per year with only a few modifications, while new buildings can operate at 1,200 MJ/m^2 per year.[12] Energy-conserving commercial buildings that use heat pumps to extract the available heat from lights, people, and passive solar radiation can have consumption levels below 700 MJ/m^2 per year.[13] A shift to this type of building for a large segment of new construction could greatly reduce the energy requirements of this sector.

An example of an energy-efficient commercial building is the Ontario Hydro building in Toronto, which uses a glazed glass exterior to assist in reducing the output requirements of the building's heating system. In a large commercial office building, the main load on the space conditioning system is usually the cooling required to reduce passive heat gains from a variety of sources. Heat given off by people, lights, and machines tends to cause higher temperature levels in the centre of the building and lower temperature levels near the perimeter. The exterior of the Hydro building reflects the sun in the summer, reducing the building's air conditioning load, and reflects internally generated heat back into the interior, reducing the winter heating load. Heat pumps are used to remove heat generated in the middle of the building and pump it to the exterior, while water tanks in the basement are used to store the heat for future use. This building consumes about 700 MJ/m^2 per year, or less than one-half of the amount consumed in the majority of buildings. Other buildings that have achieved low energy consumption levels are the Gulf Building in Calgary and the Revenue Canada Building in Oshawa. Table 6.5 provides a summary of how energy demand in the commercial sector would grow based on different assumptions about the penetration rate of new buildings designed for energy conservation.

Table 6.5 Commercial Sector Energy Consumption in Ontario by the Year 2000, as Influenced by the Penetration of Energy-Conserving Buildings between 1975 and 2000, in terajoules

	0%	10%	25%	50%	75%	100%
Existing buildings (1,500 MJ/m^2/year)	232,000	232,000	232,000	232,000	232,000	232,000
New buildings (1,200 MJ/m^2/year)	170,000	152,000	128,000	84,000	42,000	–
Energy conserving buildings (700 MJ/m^2/year)	–	9,000	23,000	46,000	70,000	93,000
Total	402,000	393,000	383,000	362,000	344,000	325,000
Growth rate in energy consumption (% p.a. 1975-2000)	1.4	1.3	1.2	1.0	0.8	0.5

Source: Based on the projection of commercial space from the Ministry of Energy submission on electricity demand presented to the Select Committee on Ontario Hydro Affairs on February 23, 1979.

Industrial Sector

In 1975, energy use in the industrial sector amounted to 814,000 TJ. Of this total, 300,000 TJ was for process-steam, 237,000 TJ was for direct heat, 115,000 TJ was for space heating and ventilation, and 162,000 TJ was for motive power.[14]

For process-steam and direct heat requirements, the use of more continuous processes, waste heat recovery, and co-generation can reduce energy consumption per unit of output by about 25 per cent overall. Improvements in insulation, better control of heating and cooling temperatures, and the use of

recoverable by-product heat from industrial processes could significantly reduce space heating and ventilation requirements, perhaps by as much as 75 per cent.[15]

Motive power requirements can also be significantly reduced. The average efficiency of motor operation in the Ontario manufacturing industry is about 52 per cent. This inefficiency is caused largely by the low load factors at which most motors are operated. When energy costs were low, efficiency was not an important consideration, and oversized motors were purchased so that peak demands could be met with minimum capital investment. By 2000, most motors now in use will have been replaced; a better matching of motor size to average load, with the use of back-up motors for peak demand, could increase average efficiency to 75 per cent.

Table 6.6 indicates how energy demand in the industrial sector might grow, with and without conservation measures, assuming an average annual economic growth rate of 3.5 per cent per annum from 1980 to the year 2000. The conservation scenario represents a significant de-coupling of energy from the economic growth rate.

Table 6.6 Industrial Sector Consumption of Energy, in terajoules

	1975	1980 (estimated)	2000 No conservation	2000 Conservation
Process heat	537,000	622,000	1,244,000	933,000
Motive power	162,000	188,000	376,000	282,000
Space conditioning and ventilation	115,000	133,000	266,000	200,000
Total	814,000	943,000	1,886,000	1,415,000
Energy growth rate 1975-2000			3.4% p.a.	2.2% p.a.

Note: Assumed economic growth rates 1980-2000 – 3.5%. 1975-80 – 3.0%.
Source: Based on Ontario Hydro, "Evaluation of Energy Requirements in Ontario Industries", Report No. PMA 76-1, February 1976.

Transportation Sector

In 1975, energy consumption in the transportation sector in Ontario was 374,000 TJ for passenger transportation and 226,000 TJ for goods transportation. A doubling of efficiency per passenger mile will likely occur by the year 2000, as average automobile fuel consumption, previously at 6 km/L, will increase to at least 11.7 km/L by 2000. (11.7 km/L represents the legislated fleet mileage of automobiles to be sold in 1985, and so by 2000 average automobile efficiency will be at least that or better.) In addition, a shift to more efficient forms such as bus, rail, and urban public transit could improve fuel efficiencies even further. Goods transportation could achieve a 25 per cent reduction in energy use if similar efficiency improvements were instituted. Table 6.7 indicates to what extent energy growth in the transportation sector might be reduced, on the basis of the above assumptions. Although a doubling of passenger travel is assumed from 1980 to 2000, energy requirements will remain almost the same due to the efficiency improvements implied by this conservation scenario.

Table 6.7 Ontario Transportation Sector Energy Consumption, in terajoules

	1975	1980	2000 No conservation	2000 Conservation
Passenger	374,000	434,000	868,000	434,000
Goods	226,000	262,000	524,000	393,000
Total	600,000	696,000	1,392,000	827,000

Note: Growth rate under conservation 1975-2000 – 1.3 per cent per annum.
Source: 1975 estimates from "Projection of the Final Demand for Energy in Ontario to the Year 2000", E. Haites, May 1978. Growth in activity is 3.4 per cent per annum. Efficiency improvements in the conservation scenario are such that passenger transportation requires half as much energy per passenger-mile and goods transportation requires three-quarters as much energy per ton-mile by 2000, compared with present energy efficiency.

Summary

Conservation is perhaps the most economical energy-related investment Ontario can make. For example, increasing insulation levels in housing to save a unit of energy is less expensive than building new energy-production facilities to create a unit of energy. Assuming implementation of the insulation levels contained in the National Research Council's "Measures for Energy Conservation in New Buildings", even with a 1.5 million (37.5 per cent) increase in the number of Ontario dwellings from 1975 to

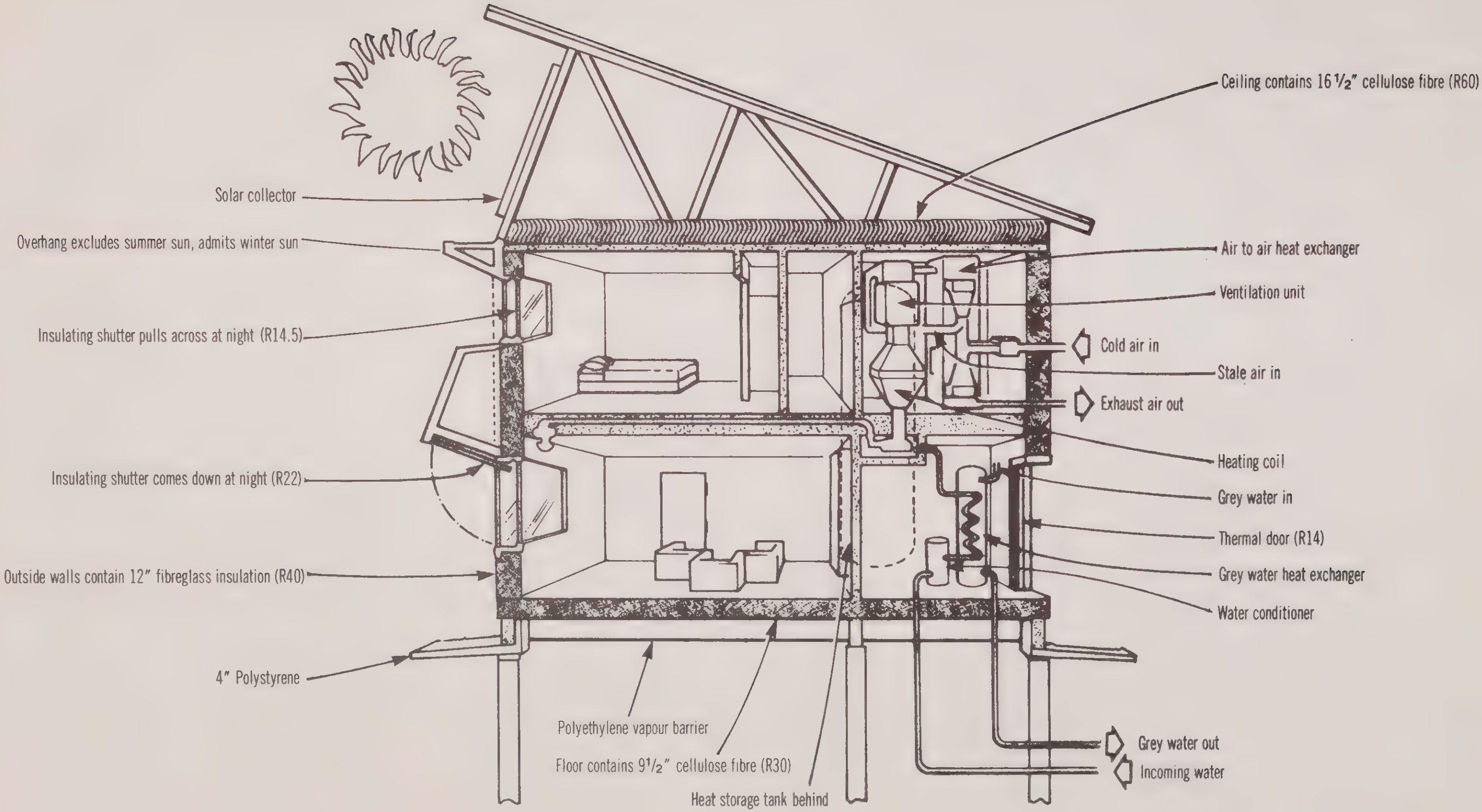
the year 2000, the additional energy requirement would be only 40,000 TJ, representing a 9 per cent increase in total energy consumption.

In the commercial sector, the development of more energy-efficient designs for buildings could result in considerable savings. Where both heating and cooling is required, especially in large commercial buildings, the use of heat pumps could cut energy consumption by 50 per cent. Overall growth of energy consumption in this sector could range from 0.5 to 1.4 per cent per year, depending on the extent to which energy-conservation measures are implemented in new commercial buildings.

In the industrial sector, as energy costs continue to climb, the use of energy-conserving equipment and production methods will increase. Waste-heat recovery, the use of continuous processes, and the use of smaller motors at higher loads would save significant amounts of energy. The annual growth rate of industrial energy consumption could be reduced from an estimated 3.4 to 2.2 per cent if energy-conservation measures are implemented.

Efficiency improvements such as the use of smaller cars and more public transit will most likely limit any increase in Ontario's transportation energy requirements, even with a doubling of travel activity.

Figure 6.1 Cross-Section of the Saskatchewan Conservation House



Source: Saskatchewan Department of Mineral Resources.

CHAPTER SEVEN

Inter-fuel Substitution

One of the most important factors in determining how the use of electricity will grow is the extent to which it is used as a substitute for other energy sources. Conversely, other energy sources may be substituted for electricity, for certain applications. The use of electricity for transportation is often suggested as a means of substituting indigenous and abundant energy sources such as uranium and water power for oil, which is less abundant and must be imported from outside the province. On the other hand, substitution of natural gas for electricity in the home-heating market is advocated on the grounds of thermodynamic efficiency; the net efficiency of using electricity to heat a home, including generation and transmission losses, is 34 per cent[1], while for natural gas heating it is about 55 per cent. For industrial process- and space-heating applications, electricity is too expensive to be competitive with fossil fuels except for a number of small applications and processes requiring extreme cleanliness and a high level of control.

Fig. 7.1: p. 73 Most statistics concerning energy use are tabulated by a sectoral breakdown into residential, commercial, industrial, and transportation consumption. Figure 7.1 gives an approximation of the amount of energy now being consumed in each of these sectors in Ontario, as well as an estimate of energy consumption by fuel type. While it is convenient to examine energy use from this perspective, in trying to assess the extent to which inter-fuel substitution might occur it is necessary to take a more detailed look at energy utilization according to the space heat, process heat, and necessary electricity requirements of the various sectors.

Residential and Commercial Sectors

In 1975, the residential and commercial sectors consumed 722,000 TJ of energy or 34 per cent of total Ontario energy consumption. Residential and commercial buildings can be heated by oil, gas, or electricity as well as by coal, wood, or solar energy. Table 7.1 indicates residential and commercial use by fuel type.

Table 7.1 End-Use Energy by Fuel Type Utilization in Residential and Commercial Sectors in Ontario in 1976, in terajoules

	Fuel type used				
	Natural gas	Petroleum	Electricity	Other	Total
Space heating	250,000	175,000	25,000	10,000	460,000
Water heating	50,000	5,000	30,000	–	85,000
Air conditioning	–	–	25,000	–	25,000
Other (farm machinery, lighting, etc.)	10,000	50,000	95,000	–	155,000
Total	310,000	230,000	175,000	10,000	725,000

Source: RCEPP.

Residential Space Heating and Water Heating

Natural Gas. In recent years, there has been a steady increase in the use of natural gas for space heating and water heating applications in the residential sector. The continued shift from oil to natural gas is largely due to the economies to be achieved by making that switch in areas already served by gas. In 1971, towns of more than 1,000 people in Ontario contained 80 per cent of the population. According to the Ontario Natural Gas Association, natural gas could probably be piped economically to these areas if they were within 10 miles (16 km) of another area served by gas. At present, about 67 per cent of new homes in the province are in areas served by gas. In such areas, over 90 per cent of new houses use gas because of its lower cost in comparison with other fuels.

Table 7.2 indicates growth trends in residential space heating and water heating over the last 15 years. Natural gas began to penetrate the Ontario heating market significantly in the late 1950s with the completion of the pipeline from Alberta. By the end of 1975, gas had replaced oil as the principal form of heating in Ontario, and at present it is being installed in 90 per cent of new homes in areas with access to gas distribution facilities. Most homes with natural gas use it for both space heating and water heating. The 1979 market price of natural gas was about $3.12/million BTU in Toronto.

Table 7.2 Growth in Residential Space Heating and Water Heating in Ontario

Fuel type	End use	Number of households 1960	1965	1970	1975
Natural gas	Space heating	243,000	514,000	778,000	1,053,000
	Water heating	280,000	457,000	706,000	1,002,000
Oil	Space heating	1,019,000	1,073,000	1,163,000	1,194,000
	Water heating	46,000	43,000	82,000	135,000
Electricity	Space heating	–	19,000	90,000	252,000
	Water heating	1,002,000	1,136,000	1,241,000	1,345,000

Source: Statistics Canada, "Household Facilities and Equipment", Report 64-202, May 1978.

By the year 2000, if gas remains available at a lower cost relative to other energy forms, up to 70-75 per cent of the households in the province could be using it. Houses switching from oil to gas space heating generally also switch from electricity to gas for water heating. In this scenario, electricity would also fall from a present market share of about 45 per cent for water heating to an ultimate penetration level of approximately 25 per cent. Homes with electrical resistance baseboard heaters are less likely to switch to gas because they must be retrofitted to add a furnace and ducts. In the longer term, perhaps, as natural gas supplies are depleted and as prices escalate, a range of diverse heating options may tend to favour revival of electrical heating, probably in an auxiliary and/or storage capacity that can easily be managed by the utility.

Oil. From 1956 to 1974, more than one-half of the households in Ontario were heated by oil. From 1960 on, the number of new households using oil has been only slightly more than the number switching to natural gas. Since 1973, the absolute number of oil-heated households has fallen as people continue to switch to gas. As a result, oil is getting almost none of the new heating market. Heating-oil prices (1979) were about $3.65/million BTU (60 cents/gallon of fuel oil).

Electricity. Electrical space heating was discouraged for many years by prohibitive pricing. In the mid 1960s, Ontario Hydro began to promote space heating heavily, and by 1978 an estimated 12.5 per cent of the households in Ontario had electrical space heating. Since 1971, about one-quarter of new households in Ontario have been equipped with electrical heat as their primary heating form. The penetration rates for electrical space heating during each year from 1975 to 1978 were 25.7 per cent, 31.0 per cent, 32.3 per cent, and 27.8 per cent respectively. Growth in electrical water heating has been slow since 1961 and there has been no growth since 1975. The growth in the number of new households with electrical space heating has been offset by the homes with oil space heating and electrical hot-water heating that have switched to natural gas for both. Ontario residential electricity prices (1979) were 2.86 cents/kW·h or $8.38/million BTU. By contrast, in Quebec the continued commitment to electrical space and water heating is a function of the economics of an almost totally hydraulic electricity supply system.

Wood Heating. Sales of wood stoves are increasing in Ontario although they are not yet at the level of the Maritimes, where energy prices are higher. Wood is a cheaper energy source where it is abundant. However, with high gathering and transportation costs, the widespread use of wood heating in cities is unlikely. Perhaps 1 per cent of all Ontario households could be using wood for heating by 2000, primarily in rural areas.

Solar Heating. A house insulated to reduce energy requirements to 50 GJ a year, with a solar-heating system providing 80 per cent of its annual energy requirements, could save $353 by replacing electricity or $220 by replacing gas (on the basis of a 60 per cent conversion efficiency for a gas furnace). If fuel price escalation equals the discount rate, then a required 30-year pay-back period would justify investments of $10,600 and $6,600, respectively, for electricity and natural gas. At present, some solar systems could be economical over a 10-15 year horizon, depending on fuel escalation rates. However, in some applications, solar water-heating systems can now be justified in preference to electrical water heating over a shorter time horizon.

The market penetration of solar heating in Ontario will depend largely upon the comparative costs of other energy forms. A study by the IBI Group[2] of solar-heating market penetration examined three time points (1976, 1986, 1996) and four heating systems (solar, oil, gas, electricity). In IBI's analysis, a conservative 20-year capitalized cost period was used for heating systems in new buildings, while in the case of retrofit the average annual cost of solar heating over a 20-year period was compared with the actual cost of heating, using conventional fuels for the year in question. Other assumptions included: a 7 per cent inflation rate; an 8 per cent or 10.5 per cent interest rate (depending upon a high or low

government incentive); an increase in electricity prices at the rate of 23 per cent per year to the end of 1979 and thereafter at 8 per cent per year in a low scenario, and 11 per cent per year in a high scenario; an installed collector cost dropping from $194/m^2 in 1976 to $129/m^2 in 1986, and to $86/m^2 by 1996 (all in 1976 dollars); and a 60 per cent solar-heating system with short-term storage and oil or natural gas back-up. Assumptions about population, employment, and new building start-ups included: 11.7 million people and 5.9 million jobs by the year 2001; 925,000 new houses under the low-density assumption and 675,000 new houses under the high-density assumption; and industrial and commercial space growing to maintain the present ratio of population to industrial and commercial space.

On the basis of these assumptions, the IBI study concluded that by 2001 between 1 per cent and 12 per cent of Ontario's space, water, and low-grade industrial heating requirements could be met by solar energy; and by 2021 this could increase to a level between 7 per cent and 33 per cent. It is important to note, however, that as higher insulation levels are implemented, the need for heating energy is dramatically reduced, which could lessen the attractiveness of the solar-heating option. This is discussed in detail in Volume 5 of this Report.

Possible Additional Electricity Requirements for Residential Heating Applications

The penetration of electrical heating in the housing market will have a large impact on electric energy requirements and an even greater impact on capacity requirements. Table 7.3 indicates additional electricity requirements for heating, depending on the level of penetration of electrical space heating and water heating.[3]

Table 7.3 Possible Additional Electricity Requirements for Residential Heating Applications by 2000 (assuming 4,000,000 Ontario households in 2000)

Penetration level in 2000		Additional generation required	
Electric space heating (%)	Electric water heating (%)	(GW·h)	(MW)
12.5	45	6,000	2,300
15	40	7,000	2,700
20	35	10,000	3,800
25	30	13,000	4,900
30	30	17,000	6,500

Source: RCEPP.

If the penetration levels of electrical space heating and water heating for Ontario's total housing stock remain at 12.5 per cent and 45 per cent, respectively, then the growth in housing by the year 2000 will result in an additional generating requirement of 6,000 GW·h of energy (6 per cent of present generation) and, at a 30 per cent load factor, about 2,300 MW of capacity (14 per cent of the 1979 system peak). If the rate of penetration of electrical space heating and water heating into the new housing market continues at 30 per cent, and if oil-users eventually switch to natural gas or electricity, then by 2000 the penetration of electricity use in households for space heating and water heating could be as high as 30 per cent. In that case, an additional 17,000 GW·h of energy (13 per cent of present generation) and 6,500 MW of capacity (33 per cent of the 1979 system peak) would be required.

The Heat Pump

The heat pump provides an alternative to conventional systems for residential and commercial space heating. A heat pump system is based on the same components as a refrigerator and operates according to the same principles. In a refrigerator, heat contained in food is transferred to a contained refrigerant gas (freon) which is then pumped into a condenser where it becomes a liquid, giving up heat in the process. The refrigerant is then forced through a constriction and, as it escapes this constraint, boils back into a gas, absorbing some of the heat from the stored food and beginning the cycle again. The same idea is incorporated in a heat pump except that heat is not taken from food but from ambient air, or from water in a well or some other heat source. The heat that is obtained is not discarded but used to warm the air inside a building.

Conventional heat pumps have been used successfully since 1949 in Ontario for residential applications, as well as in a number of large office buildings. The efficiency of a heat pump is largely determined by the temperature of the ambient air or equivalent heat source; the more heat that is stored in a source medium such as air, water, or rock, the more efficient the heat pump will be. With ambient air

temperatures in the range of -4°C to 16°C, commercially available heat pumps can improve the efficiency of an electrical heating supply by at least 50 per cent. This can be further improved, particularly at the lower end of the temperature scale, if an alternative heat source can be utilized, such as the water in a well or even the municipal water and sewage system. In the past, most heat pumps were sold on the basis of summer air conditioning requirements; however, with rising heating fuel bills, the winter energy savings that are possible with a heat pump are becoming increasingly attractive. Even with the requirement for an auxiliary heating system for very cold days, heat pumps can still offer significant energy savings.

In a recent trade publication[4], D.J. Young, a research engineer with Ontario Hydro, provided a comparison of heat-pump systems using various auxiliary heating methods or configurations, including: an all-electric heat pump, using electrical resistance back-up; an add-on heat pump, using an oil or gas furnace as the auxiliary heat source; and a hybrid heat pump that would permit simultaneous operation of both the heat pump and the auxiliary heater.

In an all-electrical system, resistance heaters are used to supply approximately two-thirds of the heating requirement on cold days. This tends to have a negative impact on the electric power load curve. On the other hand, both the add-on and hybrid heat pumps, which use a conventional combustion furnace for auxiliary heat, can reduce the utility's winter peak, because no additional electricity is required to operate the system on cold days. The difference between an add-on and a hybrid system is determined by the location of the auxiliary furnace in relation to the heat exchanger.

In the add-on system, simultaneous operation of the auxiliary heater and the heat pump is not possible, and the customer is unable to take advantage of the low cost pumped heat that is available even on the coldest days, if only in small quantities. In the hybrid system, the combustion furnace is located downstream from the heat exchanger, so that simultaneous operation can occur.

One interesting heat-pump system developed in Quebec by John Bowles, an engineer with Hydro-Québec, uses water from a 200-foot well, which provides a constant year-round heat-source temperature of 9.2°C, considerably higher than would be possible with ambient air as the source during the winter. In the Bowles system, water is passed through a heat exchanger, where high-pressure liquid freon is evaporated into its gaseous state. The heat to evaporate the freon is taken from the water, which subsequently cools to 4.5°C. Then, while the water returns to the well, the freon in its expanded gaseous form is drawn into a compressor and transformed to a hot high-pressure gas, which is then liquefied in an air-cooled condenser. (The inlet and outlet temperatures of the air to the condenser are approximately 20°C and 35°C, respectively.) The heat produced during phase-change is then carried throughout the house by a fan. Finally, the high-pressure liquid freon is evaporated by means of a pressure reduction, and the cycle starts again.

At last report, the Bowles system had operated successfully without any need of a back-up heating system. Bowles has stated that recently installed monitoring equipment indicates that his system produces more than three times the heating energy that would be produced if the electricity required to operate his system (pump, fan, compressor) were used directly for resistance home heating. For a 10-room, 3,500-square-foot (1,100 m^2) home[5] situated on the side of a mountain, this is a significant energy saving.

The Bowles system costs approximately \$650/kW to install, which compares very favourably with the \$2,000/kW expenditure for the James Bay development. The Bowles system is the first of its kind, and mass production might reduce the cost to about \$200/kW.[6]

The Effects of Heat Pump Use on Electric Energy Requirements. Space conditioning systems that provide both heating and cooling are likely to be of five different types: (1) a natural gas or oil furnace with an electrical central air conditioning unit; (2) electrical baseboard resistance heating and a central air conditioning unit; (3) an all-electric heat pump for heating and cooling; (4) a hybrid heat pump and fossil-fuel furnace with the furnace operating on days when the ambient temperature is too cold for the heat pump to operate efficiently; and (5) an add-on system in which a heat pump is added to a fossil-fuel furnace system but cannot operate simultaneously. Table 7.4 indicates the energy required for space conditioning in a single-family detached home with air conditioning based on each of the five systems. In 1978, there were about 2,700,000 households in Ontario. Of these, 12.5 per cent had electrical heating and the other 87.5 per cent had oil or gas heating. In the past, it has been suggested that heat pumps are only economical if they are used for both heating and air conditioning. Taking this into account and assuming that the ultimate market penetration for air conditioning in Ontario is 50 per cent of total

households by the year 2000, this percentage of Ontario households could feasibly install heat pumps in a retrofit situation, if the capital cost of a heat-pump system is reduced.[7]

Table 7.4 Energy Requirements for Space Heating in Single-Family Detached Homes with Air Conditioning for Five Types of Systems, in gigajoules[a]

	Electricity	Natural gas	Total energy at point of end use	Primary energy use[b]
Natural gas and central air conditioning	2	130	132	136
Electrical resistance and central air conditioning	88	–	88	251
All-electric heat pump	52	–	52	149
Hybrid heat pump system	25	40	65	111
Add-on heat pump system	12	100	112	134

Notes:

a: Apartments and units in multiple-family dwellings are assumed to have one-half of the energy requirements of single-family detached dwellings.

b) If electricity is assumed to be generated at 35 per cent efficiency.

Source: Based on seminar on the heat pump sponsored by the Canadian Energy Association in Toronto, November 1978. Information was presented by representatives from Ontario Hydro and the General Electric Company.

By the year 2000, there could be 4 million households in Ontario, including 1.3 million new ones between 1978 and 2000.[8] Of the 1.3 million new homes, roughly 25 per cent might be electrically heated and would thus be candidates for an all-electric heat pump, while the gas- or oil-heated homes could consider the hybrid heat pump. Table 7.5 indicates the difference in energy consumption, for both existing and new homes, between a "no heat pump" scenario and a scenario in which 50 per cent of new homes have heat pumps. In this example, an oil and gas saving of 57,500 TJ can be achieved with an increase of only 2,200 GW·h of electricity by the year 2000.

Table 7.5 Energy Use for Space Heating by Ontario's Housing Stock in the Year 2000

		Energy consumed[a]			
		No heat pumps		50% heat pumps	
Heating system	Number of homes (current housing mix[b])	(col. 1) Electricity (GW·h)	(col. 2) Gas or oil (TJ)	(col. 3) Electricity (GW·h)	(col. 4) Gas or oil (TJ)
Oil or gas	3,335,000	1,700	333,500	6,600	276,000
Electric	665,000	13,100	–	10,400	–
Total	4,000,000	14,800	333,500	17,000	276,000

Notes:

a) Columns 1, 2 and 3: additional electricity requirements 2,200 GW·h. Columns 2, 3 and 4: oil and gas savings equals 57,500 TJ.

b) Current housing mix (based on 1977 data): single detached – 59 per cent; single attached – 10 per cent; and apartments – 31 per cent.

Source: Based on Table 7.4 and on an estimate of heat-pump penetration for illustrative purposes.

Commercial Sector

In the commercial sector, it is likely that space heat will be provided for by much more innovative, energy-efficient designs. A number of energy-efficient office-building designs have emerged over the last few years, as discussed in Chapter 6. The Ontario Hydro building in Toronto and the National Revenue building in Oshawa both utilize the waste heat from lighting and from the occupants. Heat pumps powered by electricity can use this waste heat immediately in cooler areas, or the heat can be stored in water tanks for later use. The substitution of heat pumps for natural gas heating and electrical air conditioning would greatly increase the efficiency of air conditioning systems in commercial building space.

Industrial Sector

In 1975, Ontario industry consumed 814,000 TJ of energy, or 38 per cent of Ontario's total energy consumption.[9] Table 7.6 provides an approximation of energy utilization by fuel type and of specific end uses by various industries. Seventy per cent of the secondary energy used in industry is consumed by three major users – industrial chemicals plants, iron and steel plants, and the pulp and paper industry.

Table 7.6 Fuel Type Utilization for Specific End Uses by Industry in 1975, in terajoules

Industry end use	Natural gas	Petroleum	Coal	Electricity	Other	Total
Industrial chemicals						
Process steam	46,000	53,000	–	–	–	99,000
Direct heat	–	–	–	–	–	–
Space heat and ventilation	7,000	8,000	–	–	–	15,000
Motive power and necessary electricity	16,000	10,000	1,000	15,000	–	42,000
Total	69,000	71,000	1,000	15,000	–	156,000
Iron and steel						
Process steam	–	–	–	–	–	–
Direct heat	30,000	4,000	183,000	–	–	217,000
Space heat and ventilation	–	6,000	–	–	–	6,000
Motive power and necessary electricity	4,000	–	–	13,000	–	17,000
Total	34,000	10,000	183,000	13,000	–	240,000
Pulp and paper						
Process steam	32,000	13,000	6,000	–	15,000	66,000
Direct heat	–	–	–	–	–	–
Space heat and ventilation	6,000	2,000	–	–	–	8,000
Motive power and necessary electricity	2,000	1,000	–	22,000	–	25,000
Total	40,000	16,000	6,000	22,000	15,000	99,000
Other manufacturing						
Process steam	64,000	47,000	24,000	–	–	135,000
Direct heat	20,000	–	–	–	–	20,000
Space heat and ventilation	49,000	37,000	–	–	–	86,000
Motive power and necessary electricity	10,000	3,000	–	65,000	–	78,000
Total	143,000	87,000	24,000	65,000	–	319,000
Total manufacturing						
Process steam	142,000	113,000	30,000	–	15,000	300,000
Direct heat	50,000	4,000	183,000	–	–	237,000
Space Heat and ventilation	62,000	53,000	–	–	–	115,000
Motive power and necessary electricity	32,000	14,000	1,000	115,000	–	162,000
Total	286,000	184,000	214,000	115,000	15,000	814,000

Notes:

1. End use of fossil fuels by industry is assumed to be similar to 1972. End use based on Ontario Hydro: PMA76-1 Evaluation of Energy Requirements in Ontario Industries.
2. Coal used in iron and steel industry assumed to be used entirely for direct heat. Its chemical use in the processes was not considered.
3. Electricity uses for other than motive power and necessary electricity were considered to be small and were ignored.
4. Direct-heat processes use natural gas primarily.
5. Fuel use for co-generation based on Ontario Hydro: "Study of Industrial Electricity Generation Costs", done by Acres Shawinigan.
6. Wood waste used in pulp and paper industry used to raise process steam.

Source: RCEPP.

Process- and Space-Heating Requirements for Industry

Energy for industrial process-and space-heating requirements can be supplied by most energy sources. In 1975, about 300,000 TJ of energy was consumed by Ontario industry for raising process-steam. Natural gas is the most commonly used fuel for process-steam applications. Although electricity is at present a relatively expensive fuel for process applications, it may be preferred for direct-heat applications where fine control is desirable. In fact, many new plants that use direct-heat processes require clean fuels such as natural gas or electricity. Raising process-steam does not necessarily require clean fuel, however, and coal could be burned where environmental impacts are not a constraint. Wood is also used to raise process-steam, mostly in the pulp and paper industry.

Electrification of Process-Heat Applications. The substitution of electricity for fossil fuels to raise steam is unlikely except for very small steam-producing units, because of electricity's higher cost, at least in the near future. As of May 1978 in Toronto, industry was paying about \$6.64 per gigajoule for electric power, or about 2.5 times the price of firm natural gas for process use.[10] Although the price differential is expected to narrow, the electricity to gas price ratio is expected to remain at least 2.5.[11] While most

industries now use natural gas with a residual oil back-up, coal and wood could be substituted in the future for process-steam applications. The use of electricity can only be justified where its inherent advantages – degree of control, cleanliness, and localized use – overcome the price differential.

Direct-heat applications generally use clean natural gas or the more expensive No. 2 oil. However, substitution of electricity as the source of direct heat is possible and, as already mentioned, may be desirable in areas where fine temperature control is an asset. Industries whose major energy use is for direct-heat applications have greater potential for substituting electricity for fossil fuels. Processes now employing natural gas that could shift to electrical heating are: soaking pit operations and billet heating in the iron and steel industry; smelting of non-ferrous ores; core-drying and the melting of metals; the heat-treating of metallic parts; and the baking of non-metallic products.[12]

Other prime areas for electricity substitution, where control of temperature and cleanliness of fuel is important enough to overcome the extra cost, are: poultry-brooding in agriculture; high-temperature paint-drying in the automobile industry; the melting of iron in electrical furnaces in the iron foundries industry; and electrical arc furnaces in the iron and steel industry.[13]

Poultry-brooding could shift towards electrification because the poultry-brooders can be kept at a higher temperature than overall room temperatures by means of small localized electrical heaters. This could add about 145 GW·h[14] of electricity demand, assuming electrification of present brooding operations in Ontario.

In the automobile industry, electricity is being used for low-temperature drying, but it could also be used for high-temperature drying. This could increase electricity consumption by 700 GW·h[15], assuming electrification of all present high-temperature drying applications in the automobile industry in Ontario.

The iron foundries industry consumes an estimated 2,500 TJ to provide process heat.[16] If 50 per cent of this were provided by electricity, 700 GW·h would be consumed. Furthermore, in the iron and steel industry, open-hearth furnaces, which consume 14 kW·h/tonne of raw steel, are being replaced by basic oxygen furnaces, which consume 20 kW·h/tonne of raw steel, and electric arc furnaces, which consume 500-7,000 kW·h/tonne of raw steel.

In 1972, direct-heat processes consumed 40,000 TJ of energy. Since then, direct-heat applications have increased more rapidly than process-steam applications. If by the year 2000 electric energy were substituted to provide the equivalent of 1972 direct-heat capacity, the demand for electricity would increase by 10,000 GW·h. This would necessitate 1,600 MW of generating capacity, assuming that, on the average, plants run 70 per cent of the time.

Motive-Power Requirements

Motive-power requirements within industry will probably retain electricity as the main form of energy supply. In the pulp and paper industry, for example, trees are cut by electrically powered saws, logs are debarked by electrically powered machines, and wood chips are produced by an electrically driven mechanical chipper. This industry alone consumes 22,000 TJ of electricity to meet motive-power requirements. It is most likely that efforts by industry to improve the efficiency of motors and motor-operated processes, or to increase its own electricity generation possibilities (by co-generation), constitute a greater priority than efforts geared towards substituting other energy forms for electricity to meet motor-drive requirements.

Transportation Sector

Present Consumption

In 1975, the transportation sector in Ontario consumed 600,000 TJ, or 28 per cent of total energy consumption. More than 99 per cent of the energy used in this sector is dependent on oil as its primary source, the exception being the electrical transit system in Toronto. Table 7.7 provides a breakdown of energy used in the transportation sector by fuel type and transportation mode.

Table 7.7 Energy Use by Transportation Mode and Fuel Type Utilization in Ontario in 1976, in terajoules

	Gasoline	Diesel oil	Kerosene	Bunker oil	Total
Road					
Automobiles and trucks	420,200	47,000	–	–	467,200
Rail					
Trains	–	25,000	–	–	25,000
Air					
Jets	–	–	40,000	–	40,000
Small craft	1,800	–	–	–	1,800
Marine	–	5,000	–	18,000	23,000
Total	422,000	77,000	40,000	18,000	557,000

Source: Statistics Canada, "Detailed Energy Supply and Demand in Canada", 57-207. August 1978.

Motor Gasoline. Automobiles, buses, and trucks consumed 80 million barrels of motor gasoline in Ontario during 1976. The efficiency of gasoline-powered internal combustion engines at optimal running speed is 26 per cent, while the net output to the rear wheels has been calculated to be as low as 8 per cent of the BTU value of the gasoline.

The growth of the use of motor gasoline in Ontario was 4.8 per cent per annum between 1958 and 1974, falling to 2.4 per cent per annum between 1974 and 1975. The National Energy Board's September 1978 report on Canadian oil requirements[17] predicted a growth in the demand for motor gasoline of less than 1 per cent per annum to 1980, a decline of 0.4 per cent per annum between 1980 and 1985; and a decline of 0.6 per cent per annum between 1985 and 1995. In addition, small quantities (300,000 barrels/year) of high-grade gasoline are consumed in piston engine airplanes. Consumption rose 8.4 per cent per annum between 1959 and 1974 and 6.6 per cent per annum between 1974 and 1976.

Diesel Fuel and Heavy Fuel Oil. Total diesel fuel oil consumption for road transportation rose by 7 per cent per annum between 1958 and 1974 and by 8.7 per cent per annum between 1974 and 1976. Ontario consumption was almost 8 million barrels in 1976. Estimates by the National Energy Board anticipate a 3.3 per cent per annum growth in demand to 1995. Increased diesel use is expected because of greater engine efficiencies (30-35 per cent).

Trains were powered by coal and then by crude oil before diesel became the primary fuel in the 1950s. Ontario consumption of diesel fuel for rail transportation was 4 million barrels in 1976.

In addition, diesel fuel oil is generally used to power small boats, and residual fuel oil is used in boilers on large ships. Marine transportation consumption in 1976 was more than 800,000 barrels of diesel oil and almost 3 million barrels of heavy oil.

Kerosene. Aviation turbo fuel, which is essentially kerosene, is used in jets to power Brayton-cycle gas turbines. Consumption of aviation turbo fuel increased by 15 per cent per annum from 1958 to 1974 and 9 per cent per annum from 1974 to 1976. Ontario 1976 consumption was 7 million barrels.

Electrification of Transportation

Electricity can be substituted for oil to transport passengers and goods. Electrical cars could replace some gasoline-powered vehicles if batteries were developed with higher energy and power densities: however, their range of operation will probably limit their use to urban travel areas. Electrical transit will likely also be limited to urban centres. Electrical transit faces high capital costs, difficulty in getting rights of way, and public reluctance to use transit instead of automobiles. Besides Toronto, only Ottawa, Hamilton, London, Windsor, and Kitchener-Waterloo are likely to consider electrical transit. Rail electrification requires high capital expenditures for electrification and bed upgrading.[18] It will only be economical on high-volume routes, and thus its use for passenger traffic is dependent upon an overall increase in rail travel. By the year 2000, only the Toronto-Montreal corridor, which accounts for 40 per cent of rail passenger traffic in Ontario, is likely to be considered for electrification. In the longer term, the replacement of fossil fuels by hydrogen, produced by electrolyzing water with off-peak electricity, could greatly alter the demand for electricity in the transportation sector.

Electrical Vehicles. In Ontario, urban passenger transport currently consumes 30 per cent of transportation energy, 40 per cent of gasoline, 15 per cent of petroleum, and 7 per cent of total energy.

The electrification of all Ontario urban service and delivery vehicle traffic that operated in 1975 would save 11 million barrels of gasoline annually and require an additional 3,400 GW·h of electricity.[19] If

activity doubles by the year 2000[20], then, assuming present levels of energy intensity, 22 million barrels of gasoline would be replaced annually by an additional 6,800 GW·h of electricity. This energy could be supplied by off-peak power requiring a generating capacity of 1,630 MW based on the level of transportation activity in 1975 and 3,260 MW assuming a doubling of the 1975 level. These estimates of generating capacity requirements assume that the charging of vehicles would be distributed evenly over eight hours each weekday.

Urban energy intensity for passenger cars is about 5 km/L. The legislated 1985 sales fleet average calls for 7.5 km/L for urban travel[21], but by the year 2000 average urban passenger car energy intensity could be in the order of 10 km/L.

Consider what would happen if 50 per cent of (1979) urban passenger vehicle activity were replaced by electrically powered vehicles. At present efficiencies, this would save 20 million barrels of oil annually. The corresponding annual electricity requirement would be about 6,600 GW·h of energy, or 2,260 MW of generating capacity.[22] If passenger vehicle activity were to double by the year 2000, compared with present energy intensity, the necessary electricity generation would be 13,200 GW·h, with off-peak capacity requirements of 4,500 MW, while oil savings would be about 50 million barrels per year. Note that these savings would be half as high per unit of electricity, assuming that the fuel efficiency of conventional internal combustion engines is improved.

Electrification of Mass Transit

Electrical mass transit may be used instead of electrical cars to substitute for gasoline in urban passenger traffic. In 1975 in Ontario, electrical transit accounted for 3.7 per cent of total urban vehicular travel. The impact of any future shift will depend on the level of activity and the energy intensity of transportation. While passenger-kilometres could double by 2000, it is estimated that the energy intensity of automobiles and public transit could be reduced to 50 per cent and 70 per cent respectively, of their present intensity.[23]

Table 7.8 provides an analysis of the total energy savings and additional electricity requirements that would result from a shift towards electric urban transit. For example, by 2000, with double the present urban passenger traffic activity and improved efficiencies, electric transit could provide 20 per cent of urban passenger transportation with an electricity requirement of 2,700 GW·h and a capacity requirement of 635 MW.[24] This would save more than 30,000 TJ of energy or 7 million barrels of oil annually. However, a switch to the use of public transit faces the social problems of resistance to transit and individual preference for the convenience of the automobile.

Table 7.8 Annual Energy Saving and Electricity Requirements for Increased Electrical Urban Transit

Electrical transit as a percentage of urban passenger travel (%)	Increase in electricity requirements: Energy (GW·h)	Increase in electricity requirements: Peak (MW)	Decrease in overall secondary energy requirements (TJ)
Based on 1975 activity and energy intensity			
10	650	150	13,600
20	1,700	400	34,700
30	2,750	650	56,900
40	3,800	900	78,400
50	4,850	1,140	99,400
Based on estimated 2000 activity and energy intensity			
10	1,056	249	11,600
20	2,689	635	29,500
30	4,389	1,037	47,300
40	6,000	1,417	65,400
50	7,667	1,811	83,000

Source: Activity estimates for 1975 from "Projections of the Final Demand for Energy in Ontario to the Year 2000", E. Haites, May 1978.

Electrification of Railways. In 1976, Ontario railways consumed about 4 million barrels of diesel oil; this was 2 per cent of Ontario's petroleum consumption. Forty per cent of passenger rail traffic in Ontario is between Toronto and Montreal, and it has been suggested that this route could be electrified by 2000. If an equivalent fraction of freight traffic were also electrified, 1,000 GW·h would be required at present activity levels and 2,000 GW·h at twice present levels. Peak-demand requirements would be 360 MW at present levels and 720 MW at twice present levels, at a 30 per cent load factor.

Combined Potential

Transportation is an area where an essentially new market for electricity might be created. Present forecasts of oil shortages are possible incentives for the development of electricity-based alternatives. Table 7.9 indicates the combined potential of a reasonably high electrification scenario for the year 2000. In the example presented, 5,410 MW of electric power capacity would be required to generate 15,400 GW·h of electricity, resulting in an oil saving of 50.2 million barrels per annum.

Table 7.9 Estimates of Potential Energy Saving in the Transportation Sector as a Result of Electricity Substituting for Oil[a]

Transportation mode	Assumptions on penetration by 2000	Electric energy (GW·h)	Generating capacity required (MW)	Secondary energy saved (TJ)	Oil saved (barrels)
Urban service and delivery vehicles	50% of anticipated activity	13,400	1,630	48,000	11,000,000
Urban passenger vehicles	25% of anticipated activity	6,600	2,260	92,000	21,000,000
Urban transit	20% of total urban passenger miles	3,400	800	70,000	15,000,000
Rail passenger and freight	Windsor-Montreal corridor	2,000	720	3,000	3,200,000
Total		15,400	5,410	213,000	50,200,000

Note a) Assumes doubling of activity from 1975 levels and present levels of energy intensity.

Source: Based on 1975 transportation activity and estimated 2000 transportation activity levels, from E. Haites, 1978.

Summary

It is clear that continued growth in oil consumption should not be encouraged in Ontario.

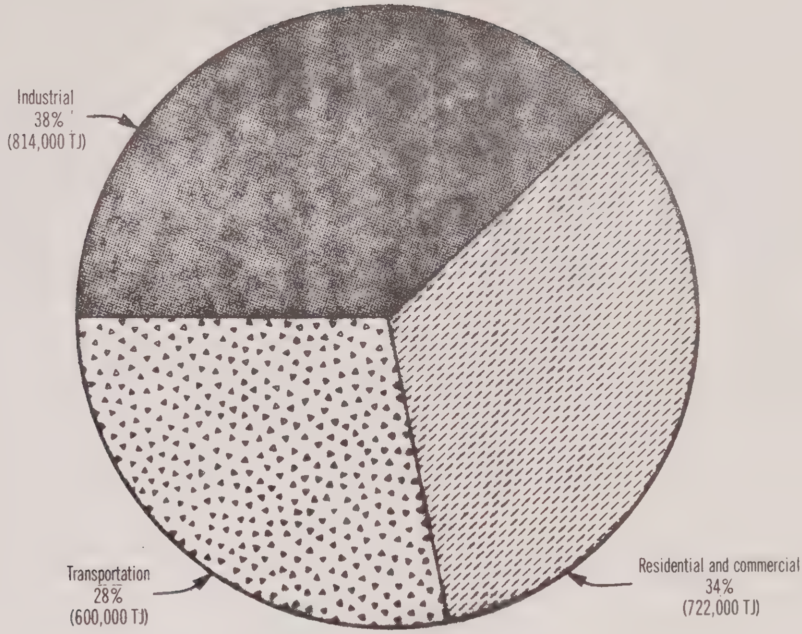
Natural gas will probably remain the major fuel for home heating in Ontario, largely because of its present (1979) lower cost. It is feasible that, by the year 2000, 75 per cent of Ontario's households will be gas-heated, especially with improvements in gas-furnace efficiencies and increased insulation levels. It is unlikely that electricity will replace gas for direct-heat applications, except perhaps for a few specialized industrial applications.

Coal will probably be used increasingly to raise process-steam, particularly as fluidized-bed combustion technology becomes available. Electricity is much too expensive for this application.

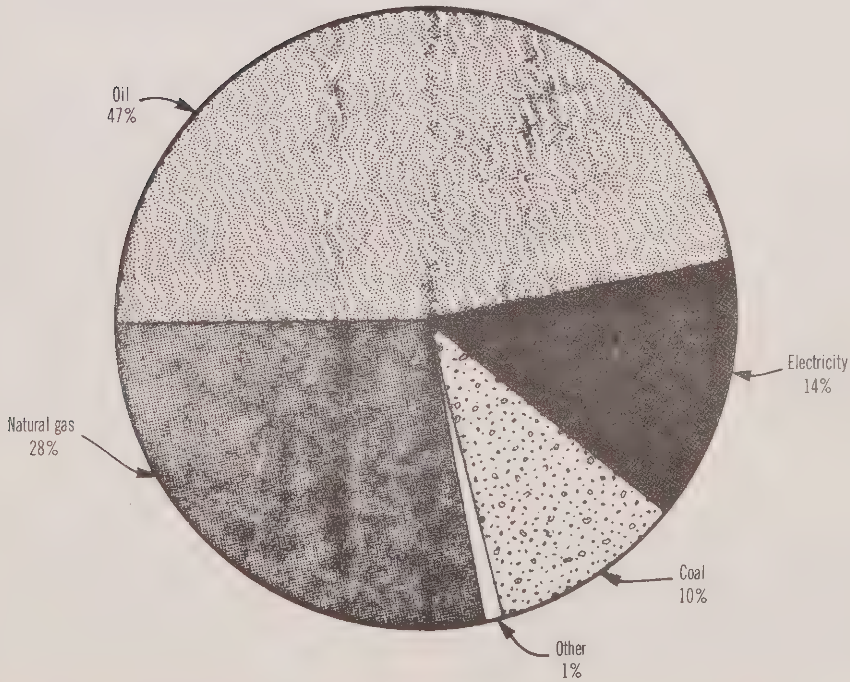
Electrification of a portion of Ontario's transportation is the most significant possible new market for electricity in the province. Electrical cars are more energy-efficient than conventional vehicles, and their use would significantly reduce fossil-fuel consumption. Even greater savings could be achieved by increasing the role of electrified public transit in comparison with other modes of transportation.

Figure 7.1 Ontario Total Energy Consumption (1975)

By sector



By fuel type



Source: RCEPP.

CHAPTER EIGHT

Ontario's Energy Opportunities

Conventional Forms of Energy Supply

There is no question that, compared with many countries, Canada is fortunate in possessing a number of undeveloped energy sources including significant oil, natural gas, coal, and uranium reserves, as well as hydro, biomass, solar, wind, geothermal, and tidal energy. The dilemma facing Canada is, not that there is an energy shortage, but that each of these energy sources carries with it a range of impacts, and most of them will be expensive to develop. Although it is generally agreed that Canada as a nation should attempt to reduce its fossil-fuel consumption, it is less clear to what extent or how quickly this could be done.

Energy consumption in Canada has more than doubled since 1960, oil and natural gas accounting for over 60 per cent of our consumption. With uncertainty about the magnitude and distribution of Canada's hydrocarbon resources and about the future costs of developing these resources, coupled with our dependence upon significant quantities of imported oil for eastern Canada, it is clear that continued growth in the consumption of oil should not be encouraged in Ontario. Furthermore, residual fuel oil is becoming less attractive as a fuel for electric power generation, as evidenced by the mothballing of Wesleyville Generating Station.

With an apparent abundance of natural gas supplies in Canada at relatively low cost, it is likely that natural gas utilization will tend to grow at a higher rate than other conventional energy forms. A further increase in natural gas utilization will occur within the next five to 10 years if current optimism regarding frontier reserves proves to be justified. This could establish an ongoing demand for natural gas, which could in turn encourage extraction of smaller and/or more remote deposits and perhaps, in the longer term, stimulate the development of coal-gasification technology adjacent to western coalfields as an eventual substitute for western Canadian natural gas.

Although the conventional natural gas resource involves minimal environmental and human impacts, high costs, uncertainty concerning assured supplies, and the existence of alternative end uses for this fuel suggest that natural-gas-fired electric power generation in Ontario will probably take place only in the form of co-generation, and specifically in areas where air pollution is considered to be a major constraint.

While coal is the most abundant of domestic fossil-fuel resources, it is also the most severe environmental offender and as a result presents some problems for Ontario. Even with improvements in coal-combustion technology, abatement costs, particularly sulphur dioxide retention systems, may add as much as 20 per cent to the operating costs of a coal-combustion system.[1] Nevertheless, with the commitment to existing contracts and the potential for future ones, it is likely that the coal-resource system will be a key component of both conventional utility-operated generating plants and industrial or municipal co-generation facilities. Despite concern over impacts at the front and back ends of the fuel cycle, the nuclear energy option continues to be the main component of Ontario Hydro's system expansion programme for base-load generation for the remainder of the century. However, lower load forecasts, escalating capital costs, rising electricity prices, competition from other forms of energy, and, perhaps most important, growing world-wide concern over the safety of nuclear power suggest that the attractiveness of nuclear energy may be in doubt for decades ahead. Concern in Canada and elsewhere about the economic viability of the nuclear components industry at current and projected order levels for reactors may further jeopardize the nuclear option.

Alternative Energy Options

Alternatives to the conventional modes of electric power generation, and to electricity as a whole, may have certain limitations but at the same time could provide an attractive range of options. Some of the possible approaches include greater utilization of renewable energy sources such as solar, wind, biomass, hydraulic, and geothermal energy. In the Commission's issue paper dealing with conventional and alternate generation technology, the question of renewable versus non-renewable energy systems is stated as follows:

The current global energy debate is concerned essentially with the rate of depletion of the non-renewable fuels (especially oil and natural gas) and with the extent to which these fuels can be replaced with renewable sources of energy or by long-term non-renewable sources such as nuclear fission and fusion.

With significant uncertainty surrounding the nuclear option, increased use of renewable energy forms coupled with more efficient energy utilization technologies appears to be fundamental to the development of an energy strategy that will take into account both the uncertainties inherent in conventional fuels and the growing environmental concerns, particularly with respect to the combustion of fossil fuels.

The manner in which renewable energy forms and efficiency improvements evolve will have a significant impact on both the operation of the electric power system and the extent to which the system will grow. For example, while there may be a certain off-peak electricity potential available to charge energy storage devices, the type and location of installations in the storage scheme could vary. The utility could operate a large centralized pumped hydro storage facility, in which off-peak electricity is stored mechanically for use during peak-demand periods. Or, smaller decentralized storage facilities, such as fuel cells and thermal storage devices, could be located in residential, commercial, or industrial complexes. Electrochemical storage used for various modes of electrified transportation would likely require extensive decentralization of storage devices with overnight charging capability. In general, the opportunities for additional large-scale centralized storage facilities are not numerous, and decentralized storage technologies appear to be better suited to the range of renewable energy options. Solar and wind energy, for example, are both intermittent and diffuse, requiring, for the most part, on-site storage to optimize the operation of these conversion systems.

With the thermodynamic inefficiencies that are associated with generating electricity to meet thermal loads, it is likely that where economic and environmental conditions permit, decentralized on-site thermal generation using a variety of fuels will be preferred. For space-heating and water-heating loads, escalating fuel costs dictate the use of higher insulation levels in all buildings and passive solar-heating designs where possible. However, it is conceivable that electricity could be used to operate auxiliary heating systems for super-insulated energy-efficient buildings.

Increasing Electrification of Energy Utilization Processes

For Ontario, a programme of greatly increased electrification replacing oil and natural gas would most likely involve a growing commitment to nuclear power generation. There are some key areas where greater electrification can be a distinct advantage. In the urban context, for example, greater electrification of transportation could reduce dependence on oil, especially if a shift from the gasoline-powered vehicle to electric public transit and electric vehicles were to occur. In addition, with certain more sophisticated heating and ventilation systems designed for energy conservation in office buildings, there may be an increased dependence upon electricity. While greater electrification in urban areas may indeed emerge, this process will be slow, determined largely by developments in the other energy-producing sectors. Furthermore, a trend towards increased electrification within urban centres may be mitigated by a shift towards non-electrification in other areas. Industrial co-generation is a key area that suggests a shift from dependence upon large-scale centralized electric power generating facilities to smaller, more localized, energy facilities that have a dual function. In addition, growth in the use of natural gas for space heating and water heating, coupled with increased insulation levels in buildings, could significantly reduce electricity demand.

The Range of Possible Energy Mixes

The shift from an energy economy based on exhaustible supplies to one based on sustainable and renewable energy sources will be a gradual one. The change will only become widespread as the existing energy infrastructure is replaced in the course of the natural wearing out of capital equipment. This time lag, coupled with the emergence of improved conversion and utilization technologies for conventional fuels, may tend to favour the implementation of certain stop-gap measures.

In the pre-2000 time frame, Ontario's energy mix should be determined largely by the extent of conservation and improved energy efficiency. However, dependence on energy sources outside the provinces will continue, with increased growth in natural gas utilization, followed by greater utilization of coal and coal derivatives, and possibly the use of hydroelectricity from Manitoba and Quebec. Growth in oil consumption should decline as conservation efforts and inter-fuel substitution occur. Of

the renewable energy options available to Ontario, the most significant are likely to be further development of biomass energy and hydro power, both of which are within current technological capability. Other indigenous fuels, particularly uranium and the Onakawana lignite deposits, will also play a significant role. If a shift towards electrification of a major portion of the transportation sector occurs, it is possible that the nuclear component of electricity generation will increase.

Beyond the year 2000, the number of energy options available to the province should be much greater. However, the availability of these options depends on the extent to which research and development is undertaken over the next 20 years both within Ontario and by other jurisdictions. Beyond 2000, concerns about fossil-fuel shortages will likely be more critical. Ontario's success in achieving a sustainable energy system will depend heavily on the ability of planners, citizens, and decision-makers to provide the necessary initiatives to deal with political and institutional inertia.

The Electric Power Component

As discussed in Volume 3 of this Report, the extent to which the demand for electricity will grow in the future depends on a number of variables, most of which are difficult to predict. Despite these complexities, however, there are a number of aspects of the problem that can be isolated and from which certain assumptions about electricity supply requirements in Ontario can be drawn. These include:

- the degree to which electricity will substitute for or be replaced by other energy technologies
- the impact of new markets or end uses on the demand for electricity
- the extent to which conservation and more efficient energy utilization will offset the growth in the demand for electricity.

In all likelihood, the rate of growth of electricity demand will rise to the 6 to 7 per cent per annum level only if widespread utilization of electricity for space-, water-, and process-heating applications occurs. As suggested in Chapter 7, new opportunities for growth in the use of electricity will probably be restricted, essentially, to two main areas:

1. Electrification of a portion of urban transportation which, even at 50 per cent penetration by the year 2000, would only require approximately 1,600-4,500 MW of additional electricity generating capacity, depending on the mix of public transit and electric car.
2. Certain direct process-heat requirements in industry, which, if one assumes a doubling of activity, amount to 40,000 TJ of energy, or a requirement for about 1,600 MW of additional generating capacity.

For space-heating and -cooling requirements, it is probable that increased penetration of natural gas heating combined with higher insulation levels will tend to reduce electric energy requirements, at least in the short term. While it is possible that more widespread use of the heat pump will lead to an increase in electricity demand, this would be offset by reductions in consumption achieved through overall energy-efficiency improvements.

Implications of Various Electricity Growth Rates on Generating Capacity Requirements

For the purposes of examining future electric power generation requirements, it is useful to consider a range of possible electricity demand growth rates at intervals of 0.5 per cent per annum growth, from 2.0 per cent to 4.0 per cent per annum, to the year 2000. Some of the generating options that are feasible to the year 2000 for meeting both base-load[2] and other[3] capacity requirements are reviewed below.

Electricity Growth Rate of 2.0 per cent per annum to the Year 2000

On the basis of an electricity growth rate of 2.0 per cent per annum, no new generating capacity, base-load or otherwise, will be required in the Ontario electric power system until beyond the year 2000. At this rate of electricity growth, consideration should be given to the postponement of a portion of committed base-load capacity which is now in the early stages of construction.

Electricity Growth Rate of 2.5 per cent per annum to the Year 2000

On the basis of an electricity growth rate of 2.5 per cent per annum, no new capacity, base-load or otherwise, will be required in Ontario's electric power system until after the year 2000. However, about 1,500 MW of intermediate, peaking, or reserve capacity may have to be replaced (the R.L. Hearn and J.C. Keith Generating Stations), assuming a 40-year life for generating stations. If this capacity is

replaced by the same type of station, there will be no change in generating mix. Alternatively, the province could meet all or part of this requirement through interconnections with Quebec and/or Manitoba.

Electricity Growth Rate of 3.0 per cent per annum to the Year 2000

For an electricity growth rate of 3.0 per cent per annum, no new intermediate, peaking, or reserve capacity will be required until beyond the year 2000. Additional base-load requirements would be in the order of 1,500 MW, which could be met by any one of several possible combinations, as shown in Table 8.1, or by interconnections with Quebec and/or Manitoba.

Table 8.1 Capacity Requirements at 3 per cent per annum Electricity Growth Rate (beyond existing and committed capacity)

Year	New base-load capacity requirements (MW)	Peaking, intermediate, and reserve capacity requirements (MW)
1990	–	–
1991	–	–
1992	–	–
1993	–	–
1994	–	–
1995	–	–
1996	–	–
1997	–	–
1998	437	–
1999	513	–
2000	528	–
Total	1,478	–

	Some possible generating technology options to meet 1,500 MW of base load by year 2000		
	Option A	Option B	Option C
Nuclear	1,500	–	–
Coal	–	–	300
Hydro	–	600	300
Biomass	–	–	–
Co-generation	–	900	900
Photovoltaic	–	–	–

Source: RCEPP.

Base-load Options – Option A – 1,500 MW of Nuclear Capacity[4]. A base-load capacity requirement of 1,500 MW could be met by two 850 MW CANDU reactors. However, it is doubtful that this amount of capacity would be sufficient to allow the domestic nuclear industry to remain viable. Present uranium contracts, which could fuel over 4,000 MW of additional nuclear capacity beyond Darlington, for 30 years at an 80 per cent capacity factor, would be sufficient for this scale of programme.

Option B – Base-load Hydro[5] *and Co-generation.*[6] Base-load hydroelectric power, in the order of 600 MW, and approximately 900 MW from co-generation could combine to meet the system requirement by the year 2000. Ontario Hydro's current programme is 800 MW from co-generation by 1985 in addition to existing facilities. Between 1985 and 2000, well over 100 additional megawatts of co-generation could become available as a supplier of base-load capacity. A hydraulic programme of 1,100 MW of peaking and intermediate capacity has been proposed by Ontario Hydro, but this would have only a 25 per cent capacity factor. The development of 600 MW of hydraulic capacity would likely require some construction on the Albany River, which would involve certain political, economic, and environmental problems.

Option C – Coal,[7] *Hydro, and Co-generation.* A combination of co-generation and hydraulic generation capacity, together with lignite from the Onakawana deposits supplying 300 MW from on-site generation, could provide 1,500 MW of base-load capacity to the Ontario Hydro grid by the year 2000. The Onakawana reserves are large enough to fuel a 1,000 MW generating station at an 80 per cent capacity factor for 30 years. With on-site generation, fuel costs would be low while transmission costs would be high. The size of the project could be limited by environmental concerns, however.

Electricity Growth Rate of 3.5 per cent per annum to the Year 2000

For an electricity growth rate of 3.5 per cent per annum, additional base-load requirements beyond existing commitments would be in the order of 3,400 MW, while additional peaking, intermediate, and reserve requirements would be about 1,500 MW, as shown in Table 8.2.

Table 8.2 Capacity Requirements at 3.4 per cent per annum Electricity Growth Rate (beyond existing and committed capacity)

Year	New base-load capacity requirements (MW)	Peaking, intermediate, and reserve capacity requirements (MW)
1990	–	–
1991	–	–
1992	–	–
1993	–	–
1994	–	–
1995	246	–
1996	592	–
1997	612	–
1998	635	178
1999	655	655
2000	680	680
Total	3,420	1,513

	Some possible generating technology options to meet 3,400 MW of base load by 2000					Some possible generating technology options to meet 1,500 MW of peaking, intermediate, and reserve by 2000			
	Option D	Option E	Option F	Option G	Option H	Option a	Option b	Option c	Option d
Nuclear	3,400	2,550	1,700	–	–	–	–	–	–
Coal	–	1,000	1,000	1,500	1,000	500	–	–	300
Hydro	–	–	–	–	1,000	1,000	1,000	1,000	1,000
Biomass	–	–	–	300	–	–	500	400	200
Co-generation	–	–	700	1,500	1,400	–	–	–	–
Photovoltaic	–	–	–	100	–	–	–	100	–

Source: RCEPP.

Base-load Options – Option D – 3,400 MW of Nuclear Capacity. One Darlington-size station of four 850 MW units could supply all of the additional base-load requirements beyond existing commitments at this rate of electricity growth. Present uranium contracts are sufficient to meet this demand. However, this may still be insufficient to ensure a viable nuclear industry in Canada.

Option E – Nuclear plus Onakawana Development. 3,400 MW of base-load capacity could be met by three 850 MW nuclear units plus development of almost 1,000 MW of on-site coal generation at the lignite mine near Onakawana. This would require additional long-distance transmission facilities from the north. As in Option D, this option would produce electric power solely from sources indigenous to the province.

Option F – Nuclear, Onakawana, and Co-generation. Two 850 MW nuclear units, 1,000 MW from Onakawana lignite, and 700 MW from co-generation could combine to meet Ontario's additional base-load capacity requirements to the year 2000 at 3.5 per cent per annum growth rate. The estimate of co-generation capacity is very conservative in view of Ontario Hydro's current forecast of 800 MW of additional co-generation capacity in place by 1985. The fuels for co-generation could be coal, oil, natural gas, or biomass.

Option G – Onakawana, Co-generation, Biomass[8], and Photovoltaics[9]. A combination of 1,000 MW from Onakawana lignite, 500 MW of additional coal capacity, 300 MW from biomass from wood waste and refuse-derived fuel, 1,500 MW from co-generation, and 100 MW from photovoltaics could supply additional base-load requirements at this electricity growth rate. This non-nuclear scenario calls for higher coal consumption and implies less reliance on indigenous sources such as uranium. The commitment to co-generation would be extensive, in comparison with what is currently anticipated before the year 2000. The photovoltaic capacity would probably be a demonstration utility project or a number of small decentralized projects.

Option H – Base-load Hydro, Onakawana, and Co-generation. Another option, involving 2,000 MW of base-load hydro, 1,000 MW from Onakawana lignite, and 1,400 MW from co-generation would require

some development on the Albany River. This would entail constructing long transmission lines and overcoming native opposition to the project.

Options for Other Modes. All reasonable options for meeting peaking, intermediate, and reserve capacity at a 3.5 per cent per annum electricity growth rate to the year 2000 assume 1,000 MW of intermediate and peaking hydraulic power based on Ontario Hydro's announced hydraulic development programme. The remaining 500 MW could be generated by a variety of peaking, intermediate, and reserve capacity options (some of which are designated by lower case letters in Table 8.2), in combination with base-load capacity options D to H.

Electricity Growth Rate of 4.0 per cent per annum to the Year 2000

At this electricity growth rate, additional capacity requirements by the year 2000 would be approximately 5,500 MW of base-load and 5,500 MW of other capacity, as shown in Table 8.3.

Table 8.3 Capacity Requirements at 4 per cent per annum Electricity Growth Rate (beyond existing and committed capacity)

Year	New base-load capacity requirements (MW)	Peaking, intermediate, and reserve capacity requirements (MW)
1990	–	–
1991	–	–
1992	–	–
1993	224	–
1994	675	458
1995	703	760
1996	730	792
1997	760	822
1998	790	856
1999	822	890
2000	854	927
Total	5,558	5,505

	Some possible generating technology options to meet 5,500 MW of base load by 2000			Some possible generating technology options to meet 5,500 MW of peaking, intermediate, and reserve by 2000		
	Option I	Option J	Option K	Option e	Option f	Option g
Nuclear	5,950	3,400	3,400	–	–	850
Coal	–	1,100	1,000	2,000	3,000	2,000
Hydro	–	–	–	3,000	2,000	2,500
Biomass	–	–	100	500	500	150
Co-generation	–	1,000	1,000	–	–	–
Photovoltaic	–	–	–	–	–	–

Source: RCEPP.

Base-load Options – Option I – Nuclear. Seven 850 MW nuclear units could provide the 5,500 MW of required base-load capacity at this rate of electricity growth. Current Ontario Hydro uranium contracts would permit 30-year fuelling at a capacity factor of 80 per cent of an additional 4,000 MW of nuclear capacity beyond Darlington. Thus, additional uranium supplies would have to be contracted. The order level for CANDU units in this scenario may be enough to sustain the nuclear industry. This option would make the electric power system less resilient but would increase provincial self-sufficiency.

Option J – Nuclear, Coal, and Co-generation. A combination of four 850 MW nuclear units, 1,100 MW from coal-fired generation including 1,000 MW using Ontario lignite, and 1,000 MW from co-generation could supply 5,500 MW of base-load capacity. Each of these supply sources is achievable without major constraints. A greater diversity of energy supply but less self-sufficiency for the province than with option I would result.

Option K – Nuclear, Coal, Biomass, and Co-generation. This option involving four 850 MW nuclear units, 1,000 MW from Ontario lignite, 100 MW from biomass, and 1,000 MW from co-generation is similar to option J but would increase the resiliency of the electric power system by using fuels indigenous to the province.

Options for Other Modes. If all peaking, intermediate, and reserve capacity options for a 4.0 per cent per annum growth rate in electricity demand were to include 2,000 MW of intermediate and peaking

hydraulic power, the additional requirement for capacity of this type would be 3,500 MW. This capacity requirement could be met in a variety of ways (some of which are designated as e, f, and g in Table 8.3), in combination with base-load capacity options I to J.

The Implications of Overall Energy Growth Rates

It is apparent that, for Ontario, growth in electricity demand beyond the 3.5 per cent per annum level will certainly require a significant commitment to additional base-load generating capacity before the end of the century. Whether or not the demand for electricity can be reduced below this level will depend on overall growth in energy consumption, the availability of fossil fuels, and the extent to which conservation and energy-efficiency improvements are implemented. For example, with a total energy growth rate of 2.0 per cent per annum and a combined oil and natural gas growth rate of 1.0 per cent per annum, an electricity growth rate of 3.5 per cent will require a 5.0 per cent per annum increase in coal consumption. If the overall energy growth rate can be reduced to 1.5 per cent per annum, then under the same assumptions coal consumption would only increase at a rate of 1.2 per cent per annum. Numerous other scenarios can be constructed, but in each case the importance of conservation as a fundamental alternative to increasing the requirement for additional energy supplies is very much apparent. Although Ontario presently possesses one of the most diversified electric power supply systems in North America (its components include hydro, coal, oil, natural gas, nuclear, and pumped storage), the trend in recent years has been towards larger-scale, more capital-intensive facilities. Even with Ontario Hydro's latest revisions of anticipated growth in electricity demand, it is apparent that the majority of required electric power generating capacity to the year 2000 is already in place. It follows that continued system expansion must take into account the lack of smaller-scale decentralized facilities, which are inherently more flexible, require less front-end capital, and offer greater potential for responding to local needs. It is likely that, in the future, as energy investments become increasingly dependent on other factors and not just the cost of a unit of energy, justification of energy projects on the basis of how they may contribute to energy self-reliance, how they may ease regional economic disparities, or how they affect the environment, will be important.

APPENDIX A

Some Non-Electrical Energy Options and Their Generalized Impact

Coal

Coal from the northeastern United States, western Canada, and the Maritimes is available to Ontario, but the quality and costs of these supplies vary greatly. As mentioned in Chapter 3, while eastern U.S. coal reserves are large, long-term availability to Ontario is uncertain. Reserves of bituminous coal in Alberta and British Columbia are estimated at up to 87 billion tonnes, but utilization is constrained by transportation costs and environmental concerns.

Extraction and Transportation of Coal

Technologies for mining, washing, and transporting coal are well known. Improvements are needed both in surface and underground mining technology to increase productivity and decrease environmental problems and health and safety hazards. Improvements are needed, particularly, in the mining of steeply pitching and severely disturbed seams of bituminous coal in the mountain areas.

The lead time to bring new coal mines into operation can be as long as that for a generating station. Five years was foreseen for Cape Breton mines; seven years is typical in the U.K. Long lead times are required for fabricating large drag lines for surface mining. Lead times for increasing rail-transport capacity are only one-half of those for bringing a new mine into operation.

Land reclamation is a problem at the front end of the coal fuel cycle. Although most coal mines, with the exception of the Onakawana reserves, are extraprovincial, the question of who should pay for land reclamation following strip-mining operations (and the extent to which it is feasible) is an important one and one that could affect the future price of coal. The cost of land reclamation has been estimated at $4,830/hectare which is the equivalent of about $0.50/tonne.

There is opposition in Alberta to extended supplying of coal to Ontario, if significant degradation would occur to valuable recreational and scenic land in strip mining in Rocky Mountain regions. However there appears to be no significant constraint on the use of semi-arid land in Saskatchewan for supplying strip-mined lignite to Ontario.

A transportation and coal-handling system for western coal has been established and is capable of handling up to 5.5 million tonnes per year. The Ontario Ministry of Energy has estimated that sufficient capacity could be in place by the year 2000 to transport 90 million tonnes of coal interprovincially across Canada.[1] However, any extensive increase in the commitment to western coal may require the construction of a coal slurry pipeline across the prairies. The technology for such a pipeline over great distances has not yet been perfected. Also, the water requirements are considerable and in semi-arid areas such as the Prairies this would be a major constraint.

Utilization and Conversion Technologies

Coal can be combusted directly to produce heat or to raise process-steam. Alternatively, it can be converted to other energy forms that are easier to transport and use. The technologies for converting coal into liquid fuels and gaseous fuels are well established and are being further developed. There are essentially three options for coal gasification – low, medium, and high BTU gasification. High-BTU gas has an energy content similar to natural gas and is commonly referred to as synthetic natural gas, or SNG. Low-BTU gas, which is essentially carbon monoxide and hydrogen, has an energy content of less than 5.6 MJ/m^3 and is generally best suited for use as an on-site boiler fuel because transportation is uneconomical over distances exceeding a kilometre. Medium-BTU gas has an energy content of about 11.2 MJ/m^3 and is most suitable for use as a petrochemical feedstock. Its economic transport range is in the order of 250-300 km.

The major obstacle to producing high-energy gas from coal is the deficiency of hydrogen in the molecular structure of coal. The overall efficiency of coal-gasification processes is 28 per cent for medium-BTU gas and 21 per cent for SNG, compared with 37 per cent for electricity. If the gasification process is integrated to produce electricity, an overall efficiency of 35 to 40 per cent is possible.

Environmentally, the gasification processes are relatively benign. Sulphur emissions are low because hydrogen sulphide can easily be removed from the gas. Similarly nitrogen oxide emissions are lower because ammonia can also be removed easily from the gas. The process requires only one-half of the cooling water used in electricity generation.

A number of gasification processes are available either at the commercial operating stage or at the pilot-plant stage. The Lurgi process and the Koppers-Totzck process for SNG production are being used in commercial facilities producing about 7 million m^3 per day. Another process near commercialization is the Winkler process. Other gasification processes at the pilot-plant stage are the Hygas, the Carbon Dioxide Acceptor, the Synthane, and the Agglomerated Burner-Gasification processes. Present low prices for conventional supplies of natural gas and high capital and operating costs for present gasification technologies make gasification unattractive – at this time. Coal gasification will likely be fully commercialized much earlier in the U.S. than in Canada because of the tighter demand-and-supply situation in the U.S. In Canada, the most important project work has been the B.C. Hydro feasibility study for gasifying the 20 billion tons of lignite at the Hat Creek Reserve in British Columbia.

Probably the most critical aspect of the energy problem is how to substitute more abundant energy forms for the rapidly dwindling supplies of liquid fossil fuels that are used for transportation. There are a number of energy forms that could eventually be substituted economically for the oil used in transportation. These include electricity for rail and urban transportation, hydrogen generated by electrolyzing water for use as an automobile and aeroplane fuel, methanol produced from biomass or coal as a fuel for automobiles, and synthetic gasoline produced by the liquefaction of coal.

Synthetic fuels were produced commercially from coal in Germany from 1930 to 1945 and have been produced in South Africa since 1960. In general, coal liquefaction is not as efficient as most low-BTU gasification processes. However, the inherent advantage of liquefaction is that the product is a liquid fuel that can be used in a variety of applications.

Several processes exist or have been proposed for liquefying coal, either by adding hydrogen to or removing carbon from the compounds in the coal. Commercial coal liquefaction facilities are planned to begin operation in the U.S. during the mid 1980s. Three processes, the SRC (Solvent Refined Coal) process, the H-Coal process, and the EDS (Exxon Donor Solvent) process, are being developed, with conversion efficiencies ranging from 60 to 70 per cent, or 2.5-3.0 barrels of fuel per ton of coal input.

A pilot plant using the SRC process has been operating at Fort Lewis, Washington, since mid 1977, producing 75 barrels per day. By 1983, a 20,000-barrel-per-day plant is planned for operation, with a capital cost of about $700 million. The Electric Power Research Institute (EPRI) predicts that 200,000 barrels a day will be produced by this process in the U.S. by 1990.

In 1979, an 1,800-barrel-per-day facility using the H-Coal process was nearing completion at Cattlesburg, Kentucky, at a cost of $100 million. By 1985, a $1.1 billion plant producing 50,000 barrels (7,940 m^3) of liquid fuel per day could be operating. By 1990, EPRI forecasts production of 150,000 barrels (23,800 m^3) per day from this process in the U.S.

In Baytown, Texas, a $100 million pilot plant producing 700 barrels (111 m^3) a day using the EDS process is scheduled to be in operation in 1980. A $1.4 billion plant producing 60,000 barrels (9,500 m^3) a day should begin operating in 1987. By 1990, EPRI forecasts 100,000 barrels (15,900 m^3) of liquid fuel per day produced from this process.

Coal liquefaction is at present uneconomical compared with other sources of liquid fuels. The technology faces several major problems. Among these are the integration of the production stages, the scaling-up of plants to commercial size, and the marketing of the products, which are different from those refined from crude oil. More effective gasifiers and catalysts are also required, and the processes cannot at present use a wide range of coals. Costs are about $6/million BTU ($5.70/GJ) if the feedstock is coal at a cost of $1/million BTU ($0.95/GJ). In general, liquefaction appears to be a more attractive option for the U.S. than for Canada because of the lower oil reserves per capita and greater U.S. reliance on oil imports.

Oil

According to U.S. estimates, once coal liquefaction becomes economically competitive, it may take 15 years to establish a 2 billion barrels (317×10^6 m^3)/day synthetic-fuel production capability.

The National Energy Board's reports on Canadian oil supply and requirements give the most up-to-date estimates of oil availability. Like natural gas, oil can be obtained from a number of locations with considerable variation in recovery and production cost.

Extraction and Transportation of Oil

Enhanced recovery from all oil sources will probably be a priority of the industry in the immediate future. Conventional recovery of reserves can extract 22 per cent of the total amount of oil that is in place, but with available improved recovery methods an additional 15 per cent can be extracted. It is expected that new, improved recovery technology, such as high-pressure gas drive, carbon dioxide mixing, chemical flooding, and thermal processes, will ultimately permit the extraction of an additional 25 per cent of the total amount. More efficient utilization of heavy oils and oil sands depends upon the introduction of on-site recovery techniques to replace the recovery techniques being used at present. Steam injection, for example, can be used to lower the viscosity of heavy oils, thereby increasing the flow. An Imperial Oil pilot plant using steam injection at Cold Lake is producing 5,000 barrels (790 m^3) per day. Future plans call for the construction of a \$5.0 billion commercial plant with a capacity of 129,000 barrels (20,500 m^3) per day by 1986.[2]

In general, approximately one barrel is consumed in the production of 10 barrels of oil from conventional sources. As the oil becomes depleted, this ratio has risen in some areas to one barrel consumed for every four barrels produced. For oil sands, the ratio may be as high as one barrel consumed for every two barrels produced. Improved refining methods that increase the fraction of light and middle distillates produced will improve the market value of the output. This is particularly important for heavy-oil and oil-sands production.

While conventional oil production processes do not result in extensive amounts of pollution, oil-sands extraction processes do. As in other mining operations, the oil is extracted from a compound, in this case one containing sand. Large amounts of water are needed for the separation process, and the waste product contains a large amount of hydrocarbon residue. Extensive development of the oil sands could have a major impact on the ecology of northern Alberta and Saskatchewan.

Offshore drilling, particularly in the Beaufort Sea and high Arctic, carries considerable environmental and occupational risks as a result of ice flows, exposure to cold, and equipment failure. The proposed arctic pipeline to bring oil from the Beaufort Sea could disrupt wildlife in the area. Transporting the oil via tanker could result in an oil spill that would have a serious impact on ocean life, particularly in the Arctic.

Capital investment costs for alternate sources of oil are high. For example, from the Syncrude Athabasca Tar Sands operation, 129,000 barrels (20,500 m^3) a day on line in 1978 required a \$2.2 billion capital investment. The production of 100,000 barrels (15,900 m^3) a day from the Imperial Oil Cold Lake oil-sands operation in 1986 is expected to cost \$5.0 billion (1979 dollars). In general terms, oil sands capital costs are estimated to be \$20,000-\$25,000 per barrel (\$126,000-\$158,000/m^3) of daily production capacity in 1978 dollars, or \$3 per barrel (\$18.90/m^3). Heavy oil capital costs are estimated to be \$5,000-\$8,000 per barrel (\$31,500-\$50,400/m^3) of daily production capacity in 1978 dollars, with a further upgrading cost of \$4,000-\$6,000 per barrel (\$24,000-\$36,000/m^3) of daily production capacity.

1979 crude oil prices were \$13.75 per barrel (\$86.63/m^3) for western Canadian crude and \$24 (U.S.) per barrel (\$150/m^3) for imported crude. Including a 12 per cent capital charge, oil sands production costs are approximately \$14-16 per barrel of synthetic crude; heavy oil costs are about \$7-11 per barrel of upgraded crude.[3] A \$1 per barrel rise in the price of crude results in a \$0.03 rise per gallon for gasoline and heating oil.

Utilization of Oil

A barrel of crude oil is first separated by distillation into products ranging from naptha to asphalt. The heavier hydrocarbons are catalytically cracked to produce lighter hydrocarbons such as gasoline and light fuel oil, while much of the gasoline is catalytically reformed to achieve higher octane ratings

allowing for more efficient combustion. The distillates from oil yield gasoline, diesel fuel, light fuel oil, kerosene, and naptha. The residual oil is used for asphalt and heavy fuel oil.

Motor gasoline is used in the transportation sector for operating automobiles and trucks. In an internal combustion engine, the energy in the gasoline is converted into mechanical energy at about 20 per cent efficiency. Further losses throughout the vehicle's drive train reduce the net output to the rear wheels to 8 per cent of the energy available in the gasoline. Ontario used 220,859 barrels (35,093 m^3) of gasoline per day in 1977.

Diesel fuel is also used to operate trains, some trucks and buses, tractors, and an increasing though still small number of automobiles. Diesel engines have higher operating efficiencies at 10 per cent net delivery to the rear wheels. Ontario used 50,706 barrels (8,058 m^3) of diesel fuel per day in 1977.

Light fuel oil is used in home-heating furnaces, where conversion efficiencies of 55 to 75 per cent can be achieved, depending on the age and condition of the furnace. Light fuel oil is also used in gas turbines for generating electricity. Ontario consumed 89,735 barrels (14,260 m^3) of light fuel oil per day in 1977.

The largest single use for kerosene is as jet fuel; its use for stoves and heating is now small. Ontario used 16,863 barrels (2,680 m^3) of kerosene per day in 1977.

Residual oil is the heavier oil left over after the lighter petroleum products have been separated by the distillation process. Residual oil is used in ship bunkering, as a source of industrial process heat, and to fire steam boilers to generate electricity. Methods of further cracking the heavy oil to produce more valuable products are available but capital costs are high. There is at present (1979) a glut of heavy oil in North America, selling at about $0.50/gallon, or about $3.00/million BTU. But it has been sold at lower spot prices to clear the market.

Incomplete combustion of oil products in automobiles and furnaces produces carbon monoxide and hydrocarbons. Furthermore, an increase in combustion temperature and pressure can result in an increase in nitrous oxides. Catalytic converters can reduce these pollutants, but they are expensive because the present technology uses a platinum catalyst. To reduce nitrous oxide emissions, the temperature and the pressure of combustion can be reduced, but this will result in lower efficiency. Alternatively, oxygen could be used instead of air to support combustion, but this would also be expensive.

Natural Gas

Natural gas is available from a number of areas in Canada. Recovery and production costs vary with the location. Estimates of the availability of natural gas in Canada are indicated in Table A.1.

Table A.1 Estimates of the Availability of Natural Gas in Canada

Source	Location	Proven reserves[a] (bcm)[c]	Ultimate potential[b] (bcm)[c]
Conventional Western Canada natural gas	Alberta and B.C.	1,900	3,600–5,700
Frontier	Beaufort Sea, N.W.T., and Atlantic Ocean	410	2,800–17,400
Deep basin	East of the foothills	28	56–50,800
Total		2,338	6,456–73,900

Notes:
a) N.E.B. estimate.
b) Range of estimates to National Energy Board.
c) bcm = billion cubic metres.

Extraction and Transportation of Natural Gas

Extraction of natural gas is done either by free flow or by gas-lift techniques. Further research and development is necessary in the recovery of gas liquids from depleted reservoirs, the processing of highly contaminated or corrosive gas, re-completions in marginal gas formations, stimulation methods for tight gas formations, and environmental monitoring. In addition, the technologies for developing frontier reserves require further development. These include technologies related to ice drilling, deep-water exploration and production, and extended pipelines. Extraction of the natural gas found in tight sands formations such as deep-basin reserves will require advanced fracturing methods. The permeability of these formations can be enhanced by chemical and hydraulic fracturing techniques.

An extensive pipeline infrastructure already exists, which facilitates delivery of western Canadian natural gas to Ontario. Exploitation of high-arctic gas would require the construction of a northern

pipeline system or the development of a liquefied natural gas (LNG) processing and transportation system using tankers.

The cost of transporting a cubic metre of gas from Alberta to Toronto is about $0.014. There are three main facilities for long-distance gas transmission in Canada. The Alberta Gas Trunk Line Company collects Alberta gas from fields and moves it to the provincial boundaries. TransCanada Pipelines Limited takes gas from the Saskatchewan-Alberta border to a point east of Winnipeg, where the system divides. One line travels north of the Great Lakes and then south to Toronto, east to Montreal, and on to the Quebec-Vermont border. The other line travels south into the United States, across the Mackinac Straits, and connects with TransCanada again at Sarnia. The third major system is that of the Westcoast Transmission Company, which transports gas from British Columbian fields to lower B.C. and the United States. The Westcoast pipeline was built from 1955 to 1957. The TransCanada system was built from 1956 to 1958. Exporting to the U.S. began in 1960.

Natural gas is distributed to individuals via pipeline on a demand basis (i.e., there is no customer storage). The three major Ontario natural gas utilities are Consumers' Gas, Union Gas, and Northern & Central Gas.

The production of frontier gas involving such installations as long pipelines across wilderness areas and the constuction of offshore drilling rigs carries some hazards with it. Arctic exploration and drilling could result in gas leaks, but this would not constitute a long-term pollutant if the well was subsequently capped, because the leaked gas would simply bubble up to the surface.

The construction of an arctic pipeline could disrupt the northern ecology by exposing permafrost layers and disrupting the migration routes of northern wildlife. The use of LNG transportation methods would increase public risk. For example, the explosion of an LNG tanker at a dock situated close to a major population area could result in a significant number of deaths.

Utilization of Natural Gas

There are at present (1979) about 1,098,000 gas consumers in Ontario. Consumption of natural gas by Ontario customers was 665 billion cubic feet (18.8 billion m^3) in 1977 and 660 billion cubic feet (18.7 billion m^3) in 1978. According to the Natural Gas Association, distribution of natural gas is economical to towns with a population of 1,000 within 10 miles (16 km) of an existing line. In 1971, 82.4 per cent of the people in Ontario lived in urban areas or areas with a population density of more than 1,000 per square mile (380/km^2).

Residential customers have a temperature-dependent demand for natural gas; only water heating and cooking demand gas in the non-heating months. Industrial users have a more even pattern of demand for gas for process heat. These customers are charged lower commercial rates because their pattern of demand makes their servicing easier. Some large industrial users consume gas only in the non-heating months and switch to coal or residual oil in the peak-demand winter months. Others are charged lower interruptible rates; they can be cut off during peak periods and therefore use boilers that are capable of using an alternative back-up fuel supply.

Gas-fired furnaces generally operate at 55-65 per cent net efficiency, but with proper maintenance some large furnaces can achieve 70 – 80 per cent efficiency. Natural gas is well suited to serve communities larger than 1,000 people (because of the distribution costs), industrial co-generation systems, and district-heating systems close to the load, because of its non-polluting characteristics. There is opposition to the use of high-quality fuel for heating boilers with a thermodynamic efficiency of less than 40 per cent. The efficiency of home furnaces is about 70 per cent, so it is usually more economical to run a gas line to each dwelling and burn the gas in individual furnaces than to combust it in a large furnace and distribute heat throughout a community via a district heating system.

During 1978, 29 billion cubic feet (820 million m^3) of natural gas were consumed in Ontario as a feedstock for the petrochemical industry. According to the National Energy Board's most recent natural gas forecast, growth in this sector of the market will not exceed 33 bcf (934 million m^3) by the year 2000. On the other hand an almost twofold increase in residential demand is anticipated during the same time frame from 139 bcf (3.9 billion m^3) in 1978 to 242.7 bcf (6.9 billion m^3) by 2000. (See Figure
Fig. A.1: p. 90 A.1)

Present federal pricing policy involves maintaining the city gate (wholesale) price of natural gas delivered to Toronto at 85 per cent of the price of a barrel of crude oil delivered to Toronto on a heat-equivalent basis. Thus, the price of natural gas will increase as oil prices are raised to world levels.

Well-head prices in Alberta are \$0.03/m^3 while exports to the U.S. are presently priced at about \$0.08/m^3. Unconventional sources of natural gas will have higher costs. LNG is expected to have landed costs of \$0.0991/m^3. Alaska natural gas delivered to California is expected to cost \$0.1557/m^3 in 1983. Arctic gas to Toronto would probably have a similar cost. Some deep-basis reserves are expected to be available at present prices, but most will only be available at a Toronto city gate price of \$0.092/m^3 or more.

Solar Energy

The almost unlimited supply of solar energy that falls on Ontario makes this energy option a desirable one as conventional, non-renewable energy forms become more scarce.

For non-electrical applications of solar energy, thermal energy from direct sunlight is captured and used directly or stored for later use in the form of low-grade heat. Solar-heating systems for space conditioning and the production of low-grade process heat generally consist of solar collectors, a storage medium, and a distribution/heat transfer mechanism. It is questionable whether homes with active solar energy systems are cost-effective at present in comparison with homes with high insulation levels and passive solar design using only a minimal amount of conventional fuels, but escalating fuel costs could make active solar systems attractive in the longer term. The operating characteristics of solar-heating sytems are difficult to predict and dependent upon weather and season. Because performance is largely dependent upon seasonal and climatic factors, some form of back-up system is required; oil, gas, wood, or coal are preferable, as electricity back-up could complicate the utility's load-forecasting efforts due to the irregularity of demands that could be placed on the system. In addition, most solar energy systems will probably require energy storage devices of one sort or another, i.e., latent heat of fusion of salt hydrate, rock bed, or water storage.

Solar collectors are available in many different designs. Some consist of a flat plate of copper or aluminum construction covered by glass, while the more recent designs incorporate evacuated tubes in which to collect the heat.

The operation of solar-heating equipment does not present any major foreseeable air, water, or solid waste pollution problems. However, improper management of antifreeze fluids (i.e., methyl hydrate) when liquid collector systems are purged for servicing could lead to some water pollution and the handling of salt hydrate canisters, if that particular storage option is used, could result in a solid waste disposal problem.

The impacts on flora and fauna are not considered to be extensive. Solar ordinances may require the removal of some trees and vegetation to allow free passage of sunlight. Migratory birds may be affected by the "mirror effect" created by solar collectors on a large scale.

Solar space heating and water heating can be developed without any major requirement for additional land if the collector systems are incorporated as part of the overall building skin. The storage-system requirement can be accommodated by underground excavation as an extension of a building's substructure. The right to light may present the biggest land-use constraint; in some cases additional land may be required to ensure adequate exposure to solar radiation.

The manufacture of solar collectors and associated hardware will require a substantial resource input which will vary according to the type of collector system and carry with it environmental and health impacts. Some of the materials required could include: copper, aluminum, glass, wood, and insulation materials. If, however, the system is incorporated into the overall building design, other materials can be saved, thereby balancing the cost.

The solar space-heating and water-heating option for Ontario will certainly require a significant increase in secondary manufacturing and would create additional employment. Some labour groups, notably the sheetmetal workers, have already shown a significant interest in supporting solar energy collection systems. In fact, the sheetmetal workers' union has sponsored a five-unit demonstration project in Toronto to examine the design and construction of solar systems in more detail.

The capital investment required to install solar space heating in Ontario is in the order of \$150/m^2 of collector or \$14/square foot.[4] Where a liquid heat transfer medium is used, the cost of anti-freeze may be a factor. In addition, the requirement for a back-up system may impose a significant fuel cost. Operating and maintenance costs will vary depending upon the quality of construction. In the Canadian climate, liquid systems will require precise maintenance to prevent the cracking of pipes on cold days. If salt hydrate storage is used, some ongoing maintenance will be required.

The overall cost of energy will depend upon the relative costs of other heating options. In New York City, for example, where electricity costs are very high, solar space heating and water heating are now

competitive. For Ontario, estimates of pay-back time range from 5 to 20 years. However, an effective home insulation programme will reduce not only the need for conventional heating fuels but the need for (and perhaps the viability of) active solar systems.

An estimate of the range of market penetration of solar space heating and water heating in Ontario by the year 2000 is discussed in Chapter 7. The extent to which the solar-heating option is developed in Ontario will depend on a number of legislative and institutional factors, including:

- a government tax policy to encourage the use of solar energy, including income tax credits or deductions, fast write-offs on capital investment for industry, and sales tax exemption
- low-interest government loans to home-owners for the installation of solar-energy systems
- implementation of solar and energy-conservation designs for government buildings wherever feasible and justified by life-cycle costs
- education and demonstration programmes promoting solar energy
- regulations to establish energy-conservation standards for new buildings, including thermal- and lighting-efficiency standards and the orientation of buildings to maximize exposure to sunlight
- where electric back-up or charging of storage devices is required, the provision of minimum or off-peak service at reduced rates
- the development of a standardized modular solar-energy system design for mass production in order to reduce overall costs.

Biomass Energy

The report of the Ontario Advisory Group on Synthetic Liquid Fuels, co-ordinated by the Ontario Ministry of Energy, coal rather than biomass would be the preferred feedstock.[5] Furthermore, with Canada's abundance of tar sands and the potential for inter-fuel substitution in order to free liquid fuel from non-essential uses, it is probable that the production of synthetic liquid fuels will not be required before the year 2000. However, as noted in Chapter 3, biomass energy can be derived from a number of organic materials such as wood, peat deposits, and waste products that are indigenous to Ontario in significant quantities.

The potential of biomass energy for Ontario is largely dependent on the use of forest and mill residues, forest surplus, and dedicated energy plantations. An accurate estimate of the extent to which these sources of wood could be available is difficult to obtain. The only extensive inventories of Ontario's forests are those relevant to the conventional forest products industry, and the potential of the energy plantation concept is unknown. Estimates of potential annual biomass supply for Ontario are in the range of 23 to 40 million ODT (oven-dried tonnes), excluding lignite and peat deposits. An estimated additional 3 million ODT per year could be obtained from municipal solid waste. The costs of supplying this biomass fuel could range from $8 to $50/ODT depending on the source and location.

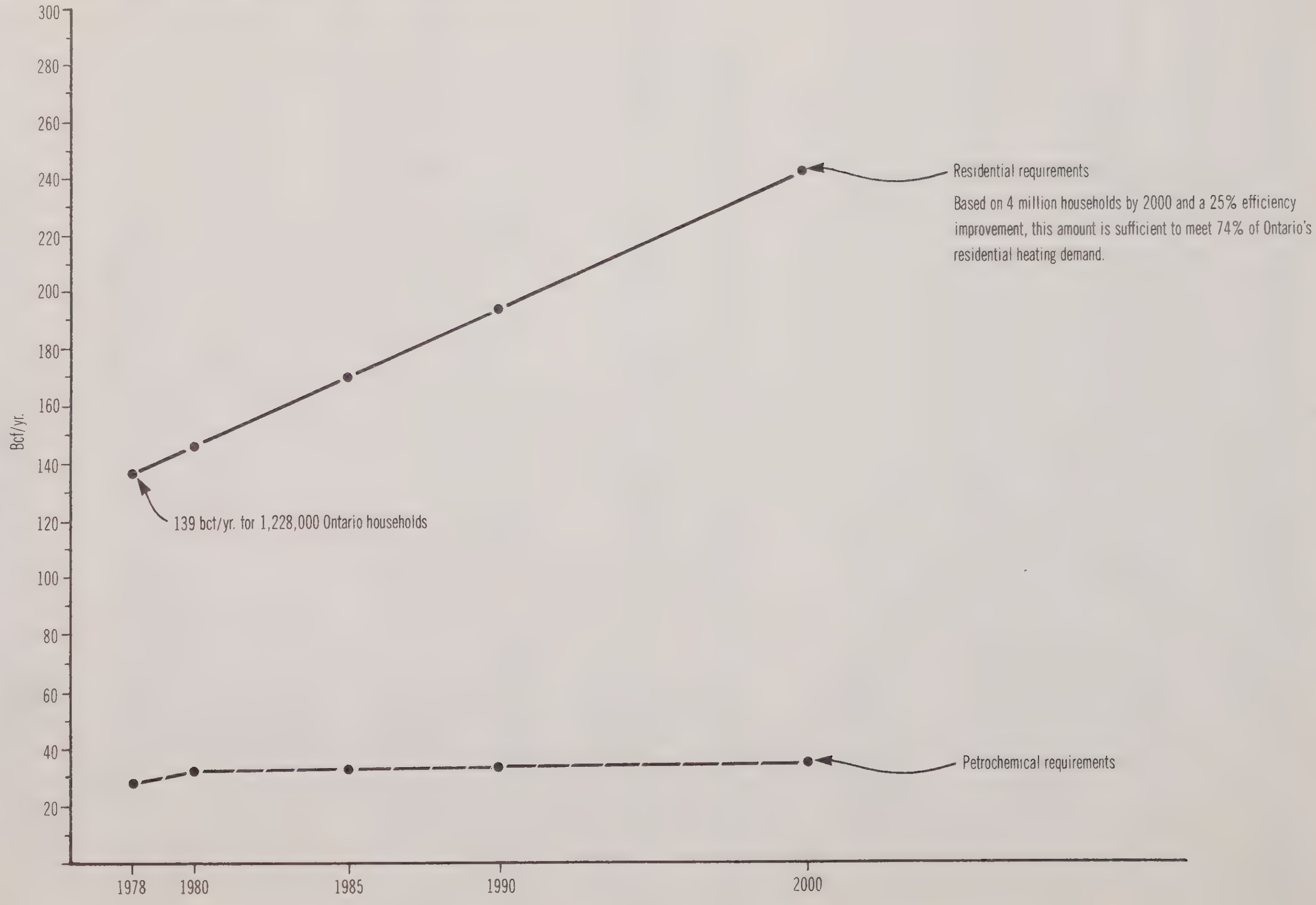
Dry biomass can be converted to a number of secondary fuels or combusted directly to produce heat. There are two general approaches to synthetic liquid fuel production using wood and municipal waste as the feedstock-biological fermentation and thermochemical processes.

Fermentation using a wood feedstock has a very low methanol yield whereas thermochemical processes are roughly four times as efficient. Of the range of thermochemical processes, gasification is best suited for the fabrication of synthetic gas for methanol production. The Purox process developed in the U.S. by Union Carbide for converting municipal wastes can convert 2.5 oven-dried tonnes of wood to 1 tonne (277 gallons) of methanol. Thus, 25 million oven-dried tonnes of wood would be sufficient to produce 10 million tonnes (2.7 billion gallons) of methanol. With an energy equivalent of about 50 per cent that of gasoline, that amount of methanol is equivalent to 1.35 billion gallons of gasoline.

Hydrogen Energy

Hydrogen energy is a possible long-term alternative to conventional fossil fuels to serve both stationary and transportation applications. The gas, which can be derived from all primary energy sources, is an ideal energy storage and transport medium. Hydrogen can be obtained from fossil fuels, as is generally the case at present where hydrogen feedstocks are required by industry, from electrolysis, and from hybrid processes as in a solar chemical reaction. In the longer term, a solar/hydrogen process may be the most attractive because of its renewable nature. In the immediate future, hydrogen could play a significant role in Ontario's electric power system as an energy-storage medium. This aspect is discussed in more detail in Chapter 4.

Figure A.1 Anticipated Growth in Natural Gas Demand — Residential Heating and Petrochemical Feedstock Requirements



Source: "Canadian Natural Gas Supply and Requirements", app. 3C, p. 124, National Energy Board, February 1979.

Units and Conversion Factors

Prefixes used

Prefix	*Multiple*	*Symbol*
kilo	10^3	k
mega	10^6	M
giga	10^9	G
tera	10^{12}	T
peta	10^{15}	P
exa	10^{18}	E

Energy and Power

Energy	*BTU*	*fp*	*J*	*kcal*	*kW·h*
1 British thermal unit =	1	777.9	1055	0.2520	2.930×10^{-4}
1 foot-pound =	1.285×10^{-3}	1	1.356	3.240×10^{-4}	3.766×10^{-7}
1 joule =	9.481×10^{-4}	0.7376	1	2.390×10^{-4}	2.778×10^{-7}
1 kilocalorie =	3.968	3086	4184	1	1.163×10^{-3}
1 kilowatt-hour =	3413	2.655×10^6	3.6×10^6	860.2	1

Power	*BTU/h*	*fp/s*	*hp*	*kcal/s*	*kW*	*W*
1 BTU/h =	1	0.2161	3.929×10^{-4}	7.000×10^{-5}	2.930×10^{-4}	0.2930
1 fp/s =	4.628	1	1.818×10^{-3}	3.239×10^{-4}	1.356×10^{-3}	1.356
1 horsepower =	2545	550	1	0.1782	0.7457	745.7
1 kcal/s =	1.429×10^4	3087	5.613	1	4.184	4184
1 kilowatt =	3413	737.6	1.341	0.2390	1	1000
1 watt =	3.413	0.7376	1.341×10^{-3}	2.390×10^{-4}	0.001	1

Length

1 foot = 0.3048 m (meter) (exactly)
1 inch = 2.54 cm (centimeter) (exactly)
1 mile = 1.60934 km (kilometer)
1 yard = 0.9144 m (exactly)

Area

1 acre = 0.404686 ha (hectare)
2.471 acres = 1 ha
1 square foot = 0.0929030 m^2
1 square inch = 6.4516 cm^2 (exactly)
1 square mile = 2.58999 km^2
1 square yard = 0.836127 m^2

Volume or Capacity

1 cord (85 stacked ft^3) = 3.62456 m^3 (stacked)
1 cord (85 ft^3 solid wood approximate) = 2.41 m^3 (solid wood approximate)
1 cubic foot = 0.0283168 m^3
35.3 cubic feet = 1 m^3
1 cubic yard = 0.764555 m^3
1 cunit (100 ft^3 of solid wood) = 2.83168 m^3
1 gallon = 0.004546 m^3
1 gallon = 4.546091 (litre) (exactly)
1 barrel (35 imperial gallons) = 0.159 m^3
6.29 barrels = 1 m^3

Mass or Weight

1 ounce = 28.3495 g (gram)
1 pound = 0.453592 kg (kilogram)
1 ton (2,000 lb) = 0.907185 t (tonne)
1.1025 pfons = 1 tonne

Temperature

°C (Celsius) = (°F-32)

Ratios

1 cord per acre = 8.95647 m^3 (stacked)/ha
1 cord per acre = 5.96 m^3 (solid wood)/ha (approximate)
1 cubic foot per acre = 0.0699725 m^3/ha
1 mile per gallon = 0.354006 km/l
1 pound per square inch = 0.0703 kg/cm^2
1 pound per cubic foot = 16.0185 kg/m^3
1 square foot per acre = 0.229568 m^2/ha
1 ton (2,000 lb) per acre = 2.24170 t/ha
1 BTU per pound = 2,327.8 J/kg
1 BTU per ton = 1.163902 J/kg
1 BTU per kW·h = 0.00029329 J/J

Alcohol Production Factors

1 gallon of alcohol = 0.0036 tonnes
1 ton of alcohol = 252 gallons = 1,145.6 litres
1 tonne of alcohol = 278 gallons = 1,263.8 litres

APPENDIX C

Bibliography

American Institute of Architects. *Energy and the Built Environment: A Gap in Current Strategies.* Washington, D.C., 1974.

Anderson, D., and R.L. Gudgeon. *Ministry of Energy District Heating Study.* Toronto: Acres Shawinigan Ltd., Exhibit 13-3, February 1976.

Barnstaple, A.G. *An Examination of the Potential for Solar Energy Utilization in Ontario.* Report No. 75092. Toronto: Ontario Hydro, Design and Development Division, Energy and Environmental Studies Dept., December 1975.

Barnstaple, D.G., et al. *Underground Thermal Energy Storage.* Report No. 77113. Toronto: Ontario Hydro, Energy and Environment Studies Department. RCEPP Exhibit 204. July 1977.

Battelle Columbus Labs. *Comparison of Fossil and Wood Fuels.* Prepared for the Industrial Environmental Research Laboratory. Washington, D.C.: U.S. Environmental Protection Agency, March 1976.

Benedek, Andrew. *Energy Saving Alternatives in Municipal Wastewater Sludge Disposal.* Hamilton: McMaster University, March 1976.

Booz, Allen & Hamilton Inc. *Commercialization of New Energy Technologies.* Final report. Prepared for the U.S. Energy Research and Development Administration. Washington, D.C., July 1976.

Brown, C.K., et al. *Energy Analysis of Resource Recovery Options.* Final report. Prepared for the Ministry of Energy and the Ministry of the Environment. Mississauga, Ontario: Ontario Research Foundation, April 30, 1976.

Brown, C.K., and D.F. Warne. *An Analysis of the Potential for Wind Energy Production in Northwestern Ontario.* A report prepared for the Ontario Ministry of Energy and Ontario Hydro by the Ontario Research Foundation and the Electrical Research Association of the United Kingdom. Mississauga, Ontario. November 1975.

Brown, C.K., in conjunction with R.M.R. Higgin. *Preliminary Assessment of Potential for Large Wind Generators as Fuel Savers in AC Community Diesel Power Systems in Ontario.* Mississuaga: Ontario Research Foundation, March 12, 1976. RCEPP Exhibit 13-2.

Canada. Energy, Mines and Resources Canada. *1978 Assessment of Canada's Uranium Supply and Demand.* Report EP 79-3. Ottawa, June 1979.

Canada. Task Force on Energy Research and Development. Office of Energy R&D. *Energy R&D Program: Task V: Exploit Renewable Energy Resources.* Program 2 - Solar Energy. Ottawa, March 1975.

Canadian Committee for the UNESCO Program on Man and the Biosphere and the Science Council of Canada. *Report of the Biomass Strategy Consultation.* February 26-8, 1979. Report No. 12. Ottawa, March 1979.

Center for Science in the Public Interest. *Solar Energy: One way to Citizen Control.* CSPI Energy Series IX. Washington, D.C., July 1976.

Central Mortgage and Housing Corporation. *The Conservation of Energy in Housing.* NHA 5149. Ottawa, 1977.

Cheng, P.N. *A Plan for Development of Hydro-Electric Generation.* Toronto: Ontario Hydro, Design and Development Division, Energy and Environmental Studies Department, June 1978.

Citizen's Advisory Committee on Environmental Quality. *Citizen Action Guide to Energy Conservation.* Washington, D.C., 1973.

Citizen's Advisory Committee on Environmental Quality. *Energy in Solid Waste; a Citizen Guide to Saving.* Washington, D.C., 1974.

Dawson, Joe. *Buying Solar.* Washington, D.C.: Federal Energy Administration, Energy Resource Development and Office of Consumer Affairs of Health Education and Welfare, June 1976.

Denton, Jesse C. *Energy Conservation Through Effective Energy Utilization.* 1973 Engineering Foundation Conference, New England College, Henniker, New Hampshire, August 19-24, 1973. Washington, D.C.: U.S. Department of Commerce, June 1976.

Dow Chemical Company. *Energy Industrial Center Study.* Prepared for the National Science Foundation. Department of Commerce, Washington, D.C., June 1975.

ECE Group. *Energy Feasibility Study for St. Lawrence – Phase B of the City of Toronto.* A working paper for the Ontario Ministry of Energy. Toronto, July 1978.

"The Economics of Industrial Cogeneration of Electricity." Seminar co-sponsored by the Ontario Ministry of Energy and Ontario Hydro, Toronto, December 13-14, 1978.

Electric Power Research Institute. *The Cost of Energy from Utility-Owned Solar Electric Systems.* A required revenue methodology for ERDA/EPRI evaluations. Pasadena, California: California Institute of Technology, Jet Propulsion Laboratory, June 1976.

Elmenius, Lars, and Stig Good. *By-Product Power as a Means to Cut Total Energy Consumption.* Finspong, Sweden, STAL-LAVAL Turbin AB, n.d.

Foster, Harold D. and W.R. Derrick Sewell. *Solar Home Heating in Canada: Problems and Prospects.* Report No. 16. Ottawa: Department of Fisheries and the Environment. Office of the Science Adviser, 1977.

Fraas, A.P. "Application of the Fluidized Bed Coal Combustion System to the Production of Electric Power and Process Heat." Paper prepared for presentation at the American Institute of Chemical Engineers, Kansas City, Missouri, April 11-14, 1976.

Gabor, D., et al. *Beyond the Age of Waste.* A report to the Club of Rome. Toronto: Pergamon Press, 1978.

Gahbauer, Steve F. *District Heating in Three Nordic Countries: What Can Ontario Learn?* Toronto: Ministry of Energy, May 1978.

Gay, B., *et al*, eds. *Low-Grade Heat: a Resource in Cold Climates.* vols. 1, 2. Proceedings of a workshop held at the Chalk River Nuclear Laboratories, October 6-10, 1975. Chalk River, Ontario: Chalk River Nuclear Laboratories, Atomic Energy of Canada Limited, January 1976.

General Electric Co., Center for Energy Systems. *Assessment of Energy Parks vs. Dispersed Electric Power Generating Facilities. Final report – vol. 1. Washington, D.C.: National Science Foundation, May 30, 1975.*

Glaser, Peter E. "The Potential of Satellite Solar Power." In *Proceedings of the IEEE*, vol. 65, no. 8, August 1977.

Glaser, Peter E. *Solar Power Satellite Development – the Next Steps.* Testimony at the hearings of the Subcommittee on Space Science and Applications and the Subcommittee on Advanced Energy Technologies and Energy Conservation Research, Development and Demonstration of the Committee on Science and Technology, U.S. House of Representatives. Washington, D.C., April 14, 1978.

Gordian Associates Inc. *Heat Pump Technology; a Survey of Technical Developments, Market Prospects and Research Needs.* HCP/M2121-01, UC-95d, Washington, D.C.: Department of Energy, June 1978.

Gorrell, H.A. "Hot Water under the Plains." *Geos*, spring 1978, pp. 12-14.

Hay, J.E. *An Analysis of Solar Radiation Data for Selected Locations in Canada.* Climatologicial Studies Number 32. Ottawa: Fisheries and Environment Canada, October 1977.

Hayes, Denis. *Energy: The Solar Prospect.* Worldwatch Paper 11. Washington, D.C.: Worldwatch Institute, March 1977.

Helferty, M.J., and R.G. Lawford. *Meteorological Information for Use in Assessing the Auxiliary Energy Requirements of Solar and Wind Energy Systems in Five Ontario Locations.* Internal Report SSU-78-9. Ottawa: Environment Canada, Ontario Region Atmospheric Environment Service, 1978.

Hill, Richard F., ed. *Energy Technology V: Challenges to Technology.* Proceedings of the Fifth Energy Technology Conference, February 27-March 1, 1978, Washington, D.C.: Government Institutes, April 1978.

Hollander, Jack M., ed. *Annual Review of Energy.* Vol. 1. Palo Alto, California: Annual Reviews Inc., 1976.

Hollands, K.G.T., and J.F. Orgill. *Potential for Solar Heating in Canada.* Prepared for the National Research Council of Canada, Division of Building Research. Waterloo: University of Waterloo Office of Research Administration, February 1977.

Hughes, Evan E., et al. *Control of Environmental Impacts from Advanced Energy Sources.* Prepared for

the Office of Research and Development, U.S. Environmental Protection Agency, Washington, D.C., March 1974.

Hurley, Charles W. and Kenneth G. Kreider. *Applications of Thermography for Energy Conservation in Industry.* Washington, D.C.: Department of Commerce, National Bureau of Standards, October 1976.

IBI Group. "Solar Heating; an Estimate of Market Penetration." RCEPP Research Report. Toronto, 1977.

InterGroup Consulting Economists Ltd. (Winnipeg). *Economic Pre-Feasibility Study: Large-Scale Methanol Fuel Production from Surplus Canadian Forest Biomass.* Part 1: Summary report. Ottawa: Fisheries and Environment Canada, Environmental Management Service, September 1976. Exhibit 120-3.

InterGroup Consulting Economists Ltd. (Winnipeg). *Liquid Fuels from Renewable Resources: Feasibility Study.* Prepared for Government of Canada. Interdepartmental Steering Committee on Canadian Renewable Liquid Fuels, Program Options. Ottawa: Fisheries and Environment Canada, May 1978.

Iverson, Stuart L., et al. *An Assessment of the Utilization of Waste Heat in Greenhouses.* AECL-5109. Pinawa, Manitoba: Whiteshell Nuclear Research Establishment, Atomic Energy of Canada Limited, January 1976.

James F. MacLaren Ltd. *District Heating Information Study.* Prepared for the Ontario Ministry of Industry and Tourism, Toronto, May 1978.

James F. MacLaren Ltd. *Feasibility of Central Heating in Downtown Sarnia.* A report. Prepared for the Ontario Ministry of Energy. Toronto, March 1979.

Littler, John G.F. *Priority in Selecting Energy Conservation Methods and Solar or Wind Heating in Houses.* Autarkic Housing Project, Working Paper 27. University of Cambridge, Department of Architecture, March 1976.

Lorriman, Douglas. *An Assessment of Problems Experienced with Operating Solar Systems in Canada and the Northern United States.* National Research Council Solar Technical Series No. 1. Ottawa: National Research Council, December 1978.

Love, Peter, and Ralph Overend. *Tree Power: An Assessment of the Energy Potential of Forest Biomass in Canada.* Report ER 78-1. Ottawa: Energy, Mines and Resources Canada, Renewable Energy Resources Branch, 1978.

Lyon, R.B., and R.O. Sochaski. *Nuclear Power for District Heating.* AECL-5117. Pinawa, Manitoba: Whiteshell Nuclear Research Establishment, September 1975.

Mackay, Donald, and R. Sutherland. *Methanol in Ontario.* A preliminary report prepared for the Ontario Ministry of Energy. Toronto: University of Toronto, November 1976.

Mackay, Robin. "Cogeneration to the Rescue." Presentation to the Electric Power Research Institute Dual Energy Use Systems Workshop held in Yarmouth, Maine, September 21, 1977.

McCallum, Bruce. *Environmentally Appropriate Technology: Renewable Energy and Other Developing Technologies for a Conserver Society in Canada.* Fourth edition. Ottawa: Fisheries and Environment Canada. Advance Concepts Centre, April 1977.

McLoughlin, G.T., and M. Reinbergs. *A New and Novel Form of District Heating Using Thermal Effluents from Electricity Generating Plants.* Paper presented at the International Conference on Alternative Energy Sources, Miami, Florida, December 4-7, 1977.

National Energy Board. *Canadian Natural Gas: Supply and Requirements.* Ottawa, February 1979.

"Net Energy Analysis Can Be Illuminating." *Conservation Foundation Letter,* October 1975. pp. 1-6.

New York Power Pool and the Empire State Electric Energy Research Corporation. *Report of the Member Electric Systems 1978.* vol. 3A: Research and Development Plans. Albany, New York, April 1, 1978.

Nicholson, Nick. *Harvest the Sun: Solar Construction in the Snowbelt.* Ayer's Cliff, Quebec: Ayer's Cliff Centre for Solar Research, 1978.

Nuttal, L.J., et al. "Feasibility Study of a Regenerative Solid Polymer Electrolyte Fuel Cell System Using Hydrogen/Chlorine Reactants for High Efficiency Energy Storage." Paper presented at the

Miami International Conference on Alternative Energy Sources, Miami Beach, Florida, December 5-7, 1977. In *Proceedings, Condensed Papers.* Washington, D.C.: Department of Energy, 1978.

Okins, Leipciger, Cuplinskas, Kaminker and Associates Ltd. *Solar Water Heating for Oakville-Trafalgar Memorial Hospital.* A feasibility study for the Ontario Ministry of Energy and the Ministry of Health. Toronto, October 1978.

Ontario Hydro. Design and Development Division. Energy and Environmental Studies Department. *Hydrogen Energy Systems: a Review of the Technologies and Economics.* Report No. 75091. Toronto, December 1975.

Ontario Hydro. Design and Development Division. Energy and Environmental Studies Department *A Review of Large Scale Power Generation Using Windmills.* Report No. 75117. Toronto, December 1975.

Ontario Research Foundation. *Solar Collector Technology Study.* Prepared for the Ontario Ministry of Industry and Tourism, Industry Branch. Toronto, September 1978.

Organisation for Economic Co-operation and Development. *World Energy Outlook.* A reassessment of long-term energy developments and related policies. A report by the Secretary-General. Paris, 1977.

Orgill, J.F., and R.M.R. Higgin. "Component Cost of Solar Energy Systems." Paper presented at Renewable Alternatives Conference of the Solar Energy Society of Canada Inc., Toronto, August 22, 1978.

Patterson, Walter C., and Richard Griffin. "Fluidized-Bed Energy Technology: Coming to a Boil." *Inform,* New York, 1978.

Patterson, Gordon N. *The Future Role of Hydrogen Fuel in an Electrical Society.* Report No. 241. Toronto: University of Toronto Institute for Aerospace Studies, September 1979.

Patterson, Gordon N. *The Race for Unlimited Energy.* Toronto: University of Toronto Institute for Aerospace Studies, 1979.

Petersen, Stephen R. *Retrofitting Existing Housing for Energy Conservation: an Economic Analysis.* Report prepared by the Center for Building Technology of the National Bureau of Standards in co-operation with the Federal Energy Administration. Washington, D.C.: Department of Commerce, December 1974.

Phung, D.L. "Unified Methodology for Cost Analysis of Energy Technologies." Paper presented at the Miami International Conference on Alternative Energy Sources, Miami Beach, Florida, December 5-7, 1977. In *Proceedings, Condensed Papers.* Washington, D.C.: Department of Energy, 1978.

Public Service Electric and Gas Co. *An Assessment of Energy Storage Systems Suitable for Use by Electric Utilities.* Final report. vols. 2 and 3. Prepared for Electric Power Research Institute and the Energy Research and Development Administration, Office of Energy Conservation. Washington, D.C., July 1976.

Resource Planning Associates Inc. *The Potential for Cogeneration Development in Six Major Industries by 1985.* Prepared for the United States Department of Energy, Office of Conservation and Solar Applications. Washington, D.C., December 1977.

Riordan, James M. and Frank J. Meawasige. "Renewable Energy Systems and Technology – Feasibility and Application to the Serpent River Indian Reserve." Prepared for the RCEPP. Exhibit 299, August 1977.

Rockingham, A.P. "The Impact of New Energy Sources on Electricity Utilities." A report prepared for the RCEPP. Toronto, May 1979.

Rogers, J.T. *Industrial Use of Low-Grade Heat in Canada.* Ottawa: Energy Research Group of Carleton University, September 1975.

Rowe, I.H., et al. *Nuclear District Heating. Study prepared for the Ontario Ministry of Energy. Presented at the Canadian Building Congress on Energy and Building, Toronto, October 25, 1976.*

Salihi, Jalal T. "Energy Requirements for Electric Cars and Their Impact on Electric Power Generation and Distribution Systems." In *IEEE Transactions on Industry Applications,* vol. 1A-9, 5, September/October 1973. pp. 516-32.

Sasaki, J.R. *Solar Heating Development in Canada and Abroad.* DBR Paper No. 726. Ottawa: National Research Council Canada, Division of Building Research, 1976.

Sasaki, J.R. *An Update to the Federal Solar Heating Program.* Building Research Note No. 122. Ottawa: National Research Council of Canada, Division of Building Research, July 1977.

Scanada Consultants Ltd. *Residential Construction Costs Entailed for Higher Levels of Thermal Resistance.* Final report for Energy and Services Division, Division of Building Research, National Research Council of Canada. Ottawa, November 12, 1976.

Science Council of Canada. *Roads to Energy Self-Reliance; the Necessary National Demonstration.* Report 30. Ottawa, June 1979. 0PB + Shurcliff, W.A. *Solar Heated Building: a Brief Survey.* With special supplement: 79 photographs by Peter Hollander. 13th and final edition. Cambridge, Massachusetts, 1977.

Stein, Richard G. *Architecture and Energy.* New York: Doubleday, 1977.

Stephenson, D.G. *Canadian Program for R&D on Energy Conservation in Buildings.* Ottawa: National Research Council of Canada, Division of Building Research, October 1976.

Stoian, E.R. *Energy R,D&D: in Search of Strategy.* Draft. Ottawa, Science Council of Canada, June 1978.

Toronto. Committee on Public Works. *Toronto District Heating study: Summary and Policy Report.* Toronto, February 13, 1974.

United States. Department of Energy. *3rd Wind Energy Workshop.* 2 vols. Washington, D.C., September 1977.

United States. Department of Energy. Research, Design and Development Panel. *Domestic Policy Review of Solar Energy.* Final report. Washington, D.C., October 1978.

United States. Energy Research and Development Administration. *Electric Energy Systems Program: Linking Sources and Uses.* Washington, D.C,: Office of Conservation, Division of Electric Energy Systems, 1977.

United States. Department of Commerce. *Energy Conservation Handbook for Light Industries and Commercial Buildings.* Washington, D.C., 1974.

United States. Energy Research and Development Administration. *A National Plan for Energy Research, Development and Demonstration.* Washington, D.C., June 1977.

United States. Energy Research and Development Administration. Division of Solar Energy. *An Economic Analysis of Solar Water and Space Heating.* Washington, D.C., November 1976.

United States. Energy Research and Development Administration. Division of Solar Energy. Environmental and Resource Assessment Branch. *Solar Program Assessment: Environmental Factors. Fuels from biomass.* Washington, D.C., March 1977.

United States. Energy Research and Development Administration. Division of Solar Energy. Environmental and Resource Assessment Branch. *Solar Program Assessment: Environmental Factors. Photovoltaics.* Washington, D.C., March 1977.

United States. Energy Research and Development Administration. Division of Solar Energy. Environmental and Resource Assessment Branch. *Solar Program Assessment: Environmental Factors. Solar Thermal Electric.* Washington, D.C., March 1977.

United States. Energy Research and Development Administration. Division of Solar Energy. Environmental and Resource Assessments Branch. *Solar Program Assessment: Environmental Factors. Solar Total Energy Systems.* Washington, D.C., March 1977.

United States. Energy Research and Development Administration. Division of Solar Energy. *Solar Thermal Energy Conversion Program. Summary Report.* Washington, D.C., October 1976.

United States. Federal Energy Administration. Office of Conservation. National Energy Conservation Program. *Impact of Load Management Strategies upon Electric Utility Costs and Fuel Consumption.* Washington, D.C., June 1977.

United States. Federal Energy Administration. Office of Energy Conservation. Transportation and Appliance Programs. *Study of Energy-Saving Options for Refrigerators and Water Heaters.* vol. 1: Refrigerators; vol. 2: Water Heaters. Washington, D.C., May 1977.

United States. Office of Technology Assessment. *Application of Solar Technology to Today's Energy Needs.* 2 vols. Washington, D.C., June 1977.

University of Oklahoma Science and Public Policy Program. *Energy Alternatives: a Comparative Analysis*. Norman, Oklahoma, May 1975.

Valaskakis, Kimon, et al. *The Conserver Society: a Workable Alternative for the Future*. New York: Harper & Row, 1979.

Wilson J.E., and A.G. Barnstaple. *Preliminary Study of Energy Storage Alternatives*. Report No. 74166. RCEPP Exhibit 198.

Wilson, W.B. "The Role of Turbines in the Paper Industry: How to Conserve Energy and Increase Profits." *TAPPI*, vol. 59, no. 6, June 1976.

Winstanley, G. *Energy Requirements Associated with Selected Energy Developments in Canada*. A summary. Report ER-78-6. Ottawa: Department of Energy, Mines and Resources, Conservation and Renewable Energy Branch, 1978.

Wondollek, J., et al. *Energy from Water Sources*. Washington, D.C.: Center for Science in the Public Interest, Citizen's Energy Project, n.d.

Notes to Chapters

Notes to Chapter One

1. "National Energy Board. *Canadian Natural Gas Supply and Requirements 1978-2000.* Ottawa, 1979. Note: Nuclear and hydro power used to generate electricity is converted to primary energy at a rate of 10,000 BTU/kW.

2. Some recent finds include: West Pembina – 80-300 million m^3 (Chevron announcements); Norman Wells – 50-100 million m^3 (Imperial Oil announcements); Beaufort Sea: rumoured large finds by Dome Petroleum.

3. J. Darmstadter, et al., *How Industrial Societies Use Energy – A Comparative Analysis.* Baltimore, Maryland, Johns Hopkins Press, 1977.

4. An excerpt from the Science Council Report, *Canada as a Conserver society,* helps to clarify this notion.

> It should not be construed, as it sometimes has been, that these prescriptons for re-directing and modifying Canadian patterns of growth are aimed at slowing, or freezing in the status quo, the productive system in which large numbers of Canadians have done well, and in which large numbers of less well-off Canadians still hope to realize their aspirations. To the contrary, within finite resources and limited environmental regenerative capacity, it is only by being more efficient, more intelligent, more far-sighted, and by changing the style of some technologies, that we shall all find room for continuing growth and distributive justice.

5. Joseph Zanyk, representing Dow Chemical Ltd., RCEPP transcript vol. 74, p. 9325.

6. A. Margison, representing Barber Hydraulic, RCEPP transcript vol. 153. pp. 20957-58.

7. Fisheries and Environment Canada. Submission to the RCEPP. Toronto, May 1977. Exhibit 120.

8. Ed Tymura, RCEPP transcript no. 221, p. 35305.

9. Frank Hooper, RCEPP transcript vol. 77, p. 9634.

10. Minnesota Pollution Control Agency, RCEPP transcript vol. 116, p. 14446.

11. M. Bein, representing Ontario People's Energy Network, RCEPP transcript vol. 121, p. 15177.

12. Bill Morison, representing Ontario Hydro, RCEPP transcript vol. 201, pp. 31622-3.

13. *Ibid.*

14. Gordon Edwards and Ralph Torrie, summary argument, RCEPP Exhibit 332.

15. Canada. Fisheries and Environment Canada. *A Review of Meteorological Information Required for the Design of Solar Energy Heating Systems in Ontario.* Internal Report SSU-77-9. Ottawa, Ontario Region, Atmospheric Environment Service, September 1977.

16. Ontario. Ministry of Treasury and Intergovernmental Affairs. *Demographic Bulletin.* (low fertility and low migration scenario). Toronto, October 1978.

17. For a detailed discussion of the baby boom and its implications for Canada see Lewis Auerbach and Andrea Gerber, *Implications of the Changing Age Structure of the Canadian Population.* Study on population and technology, Ottawa. Science Council of Canada, 1976.

18. For example, the Ontario Hydro building in Toronto and the Gulf Oil building in Calgary.

19. Some of these problems were raised during the Commission's hearings – for example in comments made by Dr. Ormrod:

> In discussing with the growers of Huron County their problems, they recollected three years ago when over a single weekend the white bean crop changed from green to brown in two days; and had there been any records taken at that time there would have been ideal worse conditions for pollution episodes ... It is our feeling now ... there may be some relationship between the disease and the smog. There is increasing evidence that smog damage or injury makes plants more sensitive to diseases ... (RCEPP transcript vol. 84, pp. 10606-16)

Note, however that many researchers believe that these impacts and acid rain evident in southwestern Ontario are the result of fossil-fuel combustion at a considerable distance up-wind, in the U.S. This is discussed in more detail in Volume 6 of this Report.

20. For example – Abitibi's mill at Smooth Rock Falls, Domtar's mill at Quevillon, Quebec, and many others, particularly in British Columbia.

21. D.L. Phung, *Unified Methodology for Cost Analysis of Energy Technologies.* Oak Ridge, Tenn., Institute for Energy Analysis, 1976.

22. Science Council of Canada. *Energy R, D & D in Search of Strategy.* Ottawa, 1978. Draft copy. Ottawa, June 1978.

23. See mid-1950s back issues of various U.S. architectural magazines.

24. The price of oil during the early 1960s was about $1.25/barrel for Middle Eastern light crude.

Notes to Chapter Two

1. Adapted from Ontario Hydro. *The Gifts of Nature.* Toronto, 1975.
2. In 1974 the utility became a Crown corporation and changed its name to Ontario Hydro.
3. The forced outage rate, expressed as a percentage, is a measure of the time a unit was out of service due to unexpected failure in comparison with the total time the unit was operated during a given period. The total time on which the forced outage rate is based does not include periods when the unit was available for service but was not operated or periods when the unit was unavailable because of overruns in the schedules for planned and maintenance outages. This is discussed in more detail in Volume 2 of this Report.
4. Acceptable reliability as defined by most utilities constitutes a loss of load probability of one day in every 10 years.
5. The accident at Three Mile Island may result in the mothballing of a $1 billion investment and lost time and wages for the people in the surrounding area.
6. Ontario Hydro plans to develop as much as 2,000 MW of hydraulic capacity at 17 sites, with an average annual output of 523 MW, equivalent to an annual capacity factor of 26 per cent. This new capacity will add to Ontario Hydro's peaking resources; see Ontario Hydro. "Systems Expansion Plan Revision". Toronto, March 1979.
7. This study was carried out in 1978 by Shawinigan-Steag Co., a subsidiary of Shawinigan Consultants International.
8. Tonnes of coal standardized at 26,000,000 BTU per ton, or about 30 GJ per tonne.
9. 48,500 tonnes from Denison over the period 1980-2011 and 27,700 tonnes from Preston over the period 1984-2020.
10. Assuming a capacity factor of 80 per cent.

Notes to Chapter Three

1. Ontario. Ministry of Energy, *Ontario Energy Review.* Toronto, June 1979. This estimate (76 billion tonnes) refers to Canadian coal reserves (excluding the Yukon and Northwest Territories) economically recoverable on the basis of present oil prices.
2. U.S. bituminous coal generally contains 8 per cent ash, 6 per cent moisture, and 2.5 per cent sulphur.
3. Measured reserves have a 100 per cent confidence level, indicated reserves have an 80 per cent confidence level. For a full definition see Canada. Energy, Mines and Resources Canada. "1977 Assessment of Canada's Uranium Supply and Demand." EP 77-3, Ottawa, June 1978. Appendix 2.
4. Canada. Energy, Mines and Resources Canada. *An Energy Policy for Canada.* Ottawa, 1973.
5. Ontario Hydro, "Generation Technical." Submission to RCEPP, Public Information Hearings. Toronto, 1976. Exhibit 2.
6. Ian Rowe, "Future Fuel Availability for Industrial Co-generation." Paper presented at the Economics of Industrial Co-generation of Electricity Seminar co-sponsored by the Ontario Ministry of Energy and Ontario Hydro. Toronto, Dec. 13-14, 1978.
7. Atikokan has been under review for possible partial postponement.
8. Ontario Hydro, "Power Resources Report." Toronto, March 1979.
9. Ontario Hydro, "Ontario Hydro North of 50°." Memorandum to the Royal Commission on the Northern Environment with respect to the initial public meetings. Toronto, 1978.
10. The Ontario Hydro grid is divided into two systems – East and West – roughly separated by a north-south line running through Wawa. The West System is much smaller, with a peak demand of about 900 MW, compared to the East System peak of almost 1,600 MW.
11. Shawinigan-Steag, Onakawana Development Study, August 1978.
12. James J. Markowsky and Bengt Wisckstrom. "170 MW Pressurized Bed Combusion Electric Plant". Paper presented to the Sixth Energy Technology Conference. Washington, D.C., February 26-8, 1979.
13. National Energy Board. *Canadian Oil, Supply and Requirement.* Ottawa, September 1978. Note that for the remainder of the discussion, the more common unit of measure – "the barrel", which equals 35 Imperial gallons – is used for oil. Approximately 6.3 barrels is equal to one cubic metre of oil.
14. Science Council of Canada. *Energy R, D & D in Search of Strategy.* Ottawa, June 1978.
15. Exchange rate on July 24, 1979, $0.8572 U.S. = $1 Canadian.
16. These levels of confidence are used in much the same way as "measured, inferred, etc." (see note 3).
17. Based on 10 per cent recoverability.

18. National Energy Board. *Canadian Natural Gas Supply and Requirements 1978-2000*. Ottawa, 1979.
19. Canadian Gas Association. "Statistical Summary – 1978". Toronto, 1979.
20. Ontario Hydro, *Annual Report*, 1978. Toronto, 1979.
21. Ontario Hydro, "Plant Capacity and Utilization 1979." Presented at an Ontario Energy Board hearing on 1979 Bulk Power Rates. Toronto, July 17, 1978. Exhibit 35.
22. Canada. Energy, Mines and Resources Canada. *1977 Assessment of Canada's Uranium Supply and Demand*. Report EP 79-3. Ottawa, 1978. Approved exports as of January 1, 1979.
23. An 80 per cent capacity factor for CANDU units is assumed throughout the section.
24. *Globe and Mail*, July 10-11, 1979.
25. For details on CANDU, see: *Interim Report on Nuclear Power in Ontario*. RCEPP. Toronto, 1978. pp. 37-51.
26. Royal Commission on Environmental Pollution. *Sixth Report: Nuclear Power and the Environment*. Chairman: Sir Brian Flowers. Her Majesty's Stationery Office, London, England, September 1976.
27. Ontario Hydro, "Generation Technical." Submission to the RCEPP, Public Information Hearings. Toronto, March 1976.
28. Royal Commission on Environmental Pollution, Op. cit.
29. *Ibid.*
30. Atomic Energy of Canada Ltd. Seminar: Proposed Canadian Fuel Cycle Program. Ottawa, February 28, 1977.
31. Science Council of Canada. *Energy R, D & D In Search of Strategy*. Ottawa, 1979.
32. J.M. Fowler, *Energy and the Environment*. Toronto, McGraw-Hill Publishing Co. 1975.
33. J.T. Rogers and J.E. Robinson, "An Assessment of Inertial Fusion as a Large-Scale Energy Source." RCEPP Research Study. Toronto, 1977.
34. Science Council of Canada. *Energy R, D & D in Search of Strategy*. Ottawa, June 1978.
35. Fisheries and Environment Canada, "Electric Power Production and Transmission in Ontario from an Environmental Perspective." Submission to RCEPP. Toronto, May 1977. Exhibit 120.
36. Morris Wayman Ltd., "Wood-fired Electricity Generation in Southeastern Ontario." RCEPP Research Study. Toronto, 1978.
37. Written and verbal communications between Morris Wayman Ltd. and the RCEPP.
38. Note that one of these boilers was converted to burn wood in June 1978.
39. Depending on the context, MSW is sometimes referred to as RDF, or refuse-derived fuel.
40. These estimates assume that power is generated from high-noon sunlight directly overhead.
41. F.H. Morse, and M.K. Simmons. "Solar Energy", in *Annual Review of Energy*, 1:131-158. Palo Alto, Calif., Annual Reviews Inc., 1976.
42. P.B. Bos, et al. *Solar Thermal Conversion Mission Analysis: Summary*. Palo Alto, Calif., Electric Power Research Institute, 1974.
P.E. Glaser, "The Potential of Satellite Solar Power", *Proceedings of the IEEE*, vol.65, 8, August 1977.
44. Ontario Research Foundation, *An Analysis of the Potential for Wind Energy Production in Northwestern Ontario*. Prepared for the Ontario Ministry of Energy and Ontario Hydro. November 1975. Exhibit 13-1.
45. M.J. Helferty and R.G. Lawford, "Meterological Information for Use in Assessing the Auxillary Energy Requirements of Solar and Wind Energy Systems in Five Ontario Locations", internal report SS4-78-9. Ottawa, Fisheries and Environment Canada, 1978. Exhibit 120-8.
46. University of Oklahoma. *Energy Alternatives: A Comparative Analysis*, Norman, Oklahoma, May 1975.
47. The proposal is to utilize wind energy to serve the base portion of the peaking system.
48. The U.S. Department of the Interior indicates that Medicine Bow has a wind potential of approximately 500 watts/m^2.
49. C.K. Brown and R. Higgin. *Preliminary Assessment of the Potential for Large Wind Generators as Fuel Savers in AC Community Diesel Power Systems in Ontario.*, Ontario Research Foundation, 1976.
50. Ontario Hydro, "Generation Technical." Submission to RCEPP, Public Information Hearings. Toronto, March 1976.
51. B. W. Colson. "Geothermal Energy from a Utility Perspective". Paper presented at Energy Technology V., Washington, D.C., February 27 to March 1, 1978.
52. *Ibid.*

Notes to Chapter Four

1. Fritz R. Kalhammer and Thomas R. Schneider. "Energy Storage". *Annual Review of Energy* Palo Alto, Calif., Annual Reviews Inc., 1976.
2. Electric Power Research Institute, *An Assessment of Energy Storage Systems Suitable for Use by Electric Utilities.* Final Report, vol. 2. Palo Alto, Calif., July 1976.
3. Ontario Hydro, "Preliminary Study of Energy Storage Alternatives." Toronto, August 1977. Exhibit 198.
4. Arnold P. Fickett, *An Electric Utility Fuel Cell: Dream or Reality?* Palo Alto, Calif., Electric Power Research Institute.
5. W.J. Lueckel and P.J. Farris. *The FCG-1 Fuel Cell Power Plant for Electric Utility Use.* Pratt & Whitney Aircraft, South Windsor, Connecticut.
6. J.F. McElroy, et al. "Feasibility Study of a Regenerative Solid Polymer Electrolyte Fuel Cell System Using Hydro/Chlorine Reactants for High Efficiency Energy Storage". Paper presented at Miami International Conference on Alternative Energy Sources, 1977.
7. G.C. Gardner, et al., "Storing Electrical Energy on a Large Scale", Research Report 2, London, Central Electricity Generating Board, May 1975.
8. Electric Power Research institute, *An Assessment of Energy Storage Systems Suitable for Use by Electric Utilities.*
9. *Ibid*, p. 3-76.
10. *Ibid*, p. 3-77.
11. *Ibid*, p. 3-78.
12. "Energy Conversion Storage and Hydrogen Systems – Program 1.8", Program Review (internal document) National Research Council, December 1978.
13. EPRI. Op. cit. p. 3-79.
14. A.W. Abdelmessih, verbal presentation to the Heat Exchanger Symposium, Toronto, April 1979.

Notes to Chapter Five

1. G.T. McLoughlin and M. Reinbergs, Office of Energy Conservation, Energy, Mines and Resources Canada, Ottawa,
2. R.B. Lyon and R.O. Sochaski. *Nuclear Power for District Heating*, Pinawa, Manitoba, Whiteshell Nuclear Research Establishment, Atomic Energy of Canada Ltd., September 1975.
3. Estimate based on Ontario Hydro submission to the RCEPP, "Energy Utilization and the Role of Electricity." Public Information Hearings, 1976. Toronto, April 1976, p. 6.5-1.
4. ECE Group. "Energy Feasibility Study for St. Lawrence – Phase B". A working paper prepared for the Ministry of Energy. Toronto, July 1978.
5. Leighton and Kidd Ltd. *Report on Industrial By-Product Power.* RCEPP Research Report. Toronto, May 1977.
6. Alex Juchymenko, ed. *Economics of Industrial Co-generation of Electricity.* Proceedings of a seminar co-sponsored by the Ontario Ministry of Energy and Ontario Hydro. Toronto, Dec 13-14, 1978.
7. Estimate by Gerry LeWarren, Morris Wayman Ltd. using steam consumption figures obtained from *Lockwood's Directory* (see Table 5.2).
8. Ontario Ministry of Energy, press release, January 1979.
9. Leighton and Kidd Ltd. Op. cit.

Notes to Chapter Six

1. National Research Council of Canada. "Commentary on Measures for Energy Conservation in New Buildings." Ottawa, 1978.
2. Ontario Hydro, "Energy Management." Toronto, April 1978.
3. Ontario Hydro, "Energy Management." Toronto, September 1978.
4. Ontario Hydro, "Energy Management." Toronto, May 1976.
5. Central Mortgage and Housing Corporation, *The Conservation of Energy in Housing.* Toronto, 1977.
6. Engineering Interface Ltd., *Report on Energy Conservation in Ontario Buildings. RCEPP Research Report. Toronto, January 1978.*
7. Dr. David Brooks, presentation to the Prince Edward Island Legislature, Douglas, Lynne & Martha Pratt, eds. *Energy Days.* Proceedings of an open seminar of the Legislative Assembly of Prince Edward Island, Charlottetown, 1976.
8. The R value is a measure of a building component's thermal resistivity. It equals the inverse of the rate of heat loss per unit area, per unit temperature change.

9. "Enercon Building Corporation, Saskatchewan", *Canadian Magazine*, Feb. 10, 1979.
10. To compare insulation investment with the investment in the new supply systems the annually adjusted investments were amortized over the 30-year period over which the investment is assumed to last. In this analysis, insulation levels are assumed to increase from R20 in the roof, R12 in the walls, and R5 in the basement to R52, R27, and R21, respectively, for electrically heated homes. For gas-heated homes, the levels increase from R10, and R5 to R38, R20, and R16, respectively. The Ontario Building Code recommends levels of R28 in the attic, R12 in the walls, and R10 in the floor.
11. Based on 1975 data.
12. Ontario Ministry of Energy.
13. *Ibid.*
14. Estimated by the RCEPP staff on the basis of available data.
15. Statistics Canada data.

Notes to Chapter Seven

1. This is the efficiency of generation from coal-fired stations. For generation from uranium, the net efficiency would be lower – about 27 per cent. However, it should be noted that uranium has no other end uses.
2. IBI Group, *Solar Heating: An Estimate of Market Penetration.* Toronto, RCEPP Research Study. 1977.
3. Assumptions:
    1. Average household uses 20,000 kW·h for electric space heating and 5,000 for electric water heating.
    2. Approximately 2,800,000 households in Ontario at present – 12.5 per cent with electric space heating and 45 per cent with electric water heating.
    3. Number of households will grow to 4,000,000 by the year 2000. Note: These assumptions also refer to Table 7.3.
4. D.R. Young, *Electrical Contractor and Maintenance Supervisor*, January 1979.
5. The Bowles home incorporates R30 in the ceiling, R20 in the walls, and has no insulation in the basement.
6. These figures ($650/kW and $200/kW) refer to the dollar cost to save 1 kW of electricity compared to the cost of producing a new kilowatt of electricity ($2,000/kW in the example of the James Bay development).
7. In 1977 almost 7.5 per cent of households had central air conditioning units and 19 per cent had window air conditioning units.
8. Estimates for Ontario housing stock by Central Mortgage and Housing Corporation.
9. This definition of energy use include petrochemical feedstocks, coke, and natural gas used in catalytic processes.
10. *Energy Analects*, September 15, 1978 and September 22, 1978.
11. Ontario Hydro, "Bulk Power Facilities S.W. Ontario Supplementary Information", Toronto, February 1979.
12. Ontario Hydro, "Energy Utilization and the Role of Electricity." Toronto, Submission to RCEPP, Public Information Hearings. April 1976. Exhibit 4.
13. *Ibid.*
14. *Ibid.*
15. *Ibid.*
16. Ontario Hydro. "Evaluation of Energy Requirements of Ontario Industries." Report PMA-1. February 1976.
17. National Energy Board, *Canadian Oil Supply Requirements.* Ottawa, September 1978.
18. Submission by Canadian National Railways to RCEPP, January 1978.
19. These figures assume end-use efficiencies of about 60 per cent for the electric car and 12 per cent for a gasoline-powered car.
20. Estimates of traffic volume for the different modes are based on 1975 figures, in E. Haites, *Projection of the Final Demand for Energy in Ontario to the Year 2000.* RCEPP Research Report. Toronto, May 1978.
21. Sales-weighted fleet mileage legislation calls for efficiencies of 33 miles per imperial gallon by 1985. The testing methods overstate consumption by at least 15 per cent giving actual efficiencies of about 28 miles per gallon (about 10 km/L). This figure is based on a breakdown of 55 per cent urban driving and 45 per cent highway driving, which is Transport Canada's estimate. From this, urban efficiency is estimated to be 21 mpg. (7.5 km/L).

22. The figures for off-peak capacity required assume that, on the average, the cars are evenly charged throughout the year for eight hours a day.
23. Present energy intensities, 650 kJ/passenger-km for electric transit, 4,300 kJ/passenger-km for the automobile. Potential intensity in the year 2000, 500 kJ/passenger-km and 2,000 kJ/passenger-km, respectively. Working group on Canadian Energy Policy, Downsview, York University, Faculty of Environmental Studies, August 1977, Exhibit 334-11. John Robinson, et al. *Canadian Energy Futures: An Investigation of Alternative Energy Scenarios 1974-2025.* Faculty of Environmental Studies.
24. Peak demand in an hour is assumed to equal the daily average demand divided by 11.6. This is the present peak hourly demand for the Toronto Transit Commission. Urban Transportation Development Corporation Ltd., *Moving Into an Energy Efficient Society.*, submission to the RCEPP. Toronto, November 1976.

Notes to Chapter Eight

1. Ontario Hydro, "Generation Technical." Submission to the RCEPP Public Information Hearings. Toronto, March 1976. Exhibit 2.
2. Assumptions Regarding Base-load Capacity: In general, base-load facilities may be defined as those that operate at full output most of the time they are available. Base-load facilities have been considered to be those whose duration of operation is 65 per cent or more of the time they are available. On the basis of present load and plant duration curves, this is about 60 per cent of the primary peak or 50 per cent of capacity, assuming a 20 per cent reserve margin. Present base-load generation technologies include nuclear power generation, coal-fired generation, and hydroelectric generation. Other options could include co-generation, with a range of possible fuels, and combined solar photovoltaic storage schemes.
3. "Other capacity" refers to intermediate, peaking, and reserve capacity. For convenience, in these scenarios, intermediate, peaking, and reserve capacities are grouped together. It should be noted, however, that other generating technologies would probably be employed for other modes of operation. These technologies include: hydroelectric generation, biomass-fired generation, fossil-fuelled generation using a variety of fuels, combustion turbines, and photovoltaic generation with storage.
4. CANDU nuclear is assumed throughout. Likely unit size is 850 MW with capital costs of $1,400/kW of installed capacity in 1985 dollars. Fuel source is indigenous uranium which could easily be supplied from inside the province with a programme of moderate size. The units would have availabilities of 75-77 per cent and could operate with capacity factors as low as 55 per cent, with weekend shut-down, or lower with part-load operation at night.

One constraint is the size of the minimum order required to keep a domestic nuclear industry viable. The Leonard and Partners study suggests that a minimum order of 1,200-1,700 MW per year is necessary to sustain the industry. A combination of increased export sales, industry rationalization, and diversification of manufacturers of components could reduce this requirement but higher costs would probably result.

Load-management and energy storage schemes could increase the base-load share of present capacity, making nuclear capacity more attractive. CANDUs with better load-following capability could be designed and built, although their high capital cost might limit their economic viability at low capacity factors. Also, stations could be built that would be dedicated to exporting power to the U.S., although there is some uncertainty as to how much electricity the U.S. might be willing to buy in the future. Earlier retirement of present facilities could increase the demand for nuclear units.

Nuclear capacity could be further constrained by concerns about reactor safety, particularly in view of the accident at Three Mile Island in Pennsylvania. Local opposition could make siting of new generating stations difficult. Further expansion could also be constrained if the industry is unable to convince the public in the near future that nuclear waste can be safely disposed of.
5. Hydroelectric units can be started up and shut-down rapidly and, as a result, stations can be designed and operated as base-load, intermediate, or peaking facilities. These units have very high reliability, and their total availability including planned outages for maintenance, is 95 per cent. At present there is 2,800 MW of base-load hydraulic capacity in the system which, operated at full availability, is capable of generating 23,000 GW·h of electricity.

The only large scale base-load hydroelectric sites remaining in the province are in northern Ontario. Harnessing the Albany River, for example, could provide 2,100 MW of average energy capacity (or 3,000 MW of peaking capacity), while the Severn River, located near the Manitoba border, could provide 600 MW of average energy capacity (or 700 MW of peaking capacity). The development of

these rivers is restrained by the high costs and the energy losses associated with electricity transmission from such remote areas. In addition, these developments could only take place with the full co-operation of the native peoples in the northern part of the province.

6. Industries with a large enough process steam requirement (greater than 100,000 pounds per hour) can generate electricity by passing this steam through a turbine before it is applied to a process. The increased capital, fuel, and steam requirements are significantly less than those of a utility designed to generate electricity alone. Co-generation could be fuelled with coal, oil, gas, or biomass. Coal would likely be used for facilities large enough to justify storage space for the fuel and pollution control equipment. Oil, gas, or biomass would likely be used in smaller facilities. Availability of co-generation units is expected to be high – in the order of 70 per cent – and these units would generally be operated by industries with three-shift, seven-day-a-week operation, which is virtually continuous.

Co-generation is economical for most industries that use at least 100,000 pounds of steam per hour and 5 MW of electricity (with a 70 per cent, or greater, load factor). At present, 22 companies in Ontario have co-generation facilities, for a total of 510 MW. A further 43 companies, totalling a peak demand of 720 MW, could be converted to co-generation by 1990. With an estimated 55 companies in addition to these, total estimated potential is about 3,000 MW. Ontario Hydro and the Ministry of Energy are engaged in a programme aimed at putting into place about 800 MW of co-generation by 1985.

7. Coal is at present not competitive in Ontario with nuclear power for base-load capacity, according to Ontario Hydro's economic analysis. With present coal technology, base-load additions would therefore be nuclear. However, several developments could make coal attractive for base-load additions in Ontario by the year 2000. These include: Onakawana lignite, fluidized-bed combustion, and magnetohydrodynamics.

8. Wood wastes in areas adjacent to logging operations, lumber mills, and sawing operations could also be used to generate electricity. Similarly, in larger cities, refuse can be fired to generate electricity. The economics of these options generally rest on the costs of gathering the fuel, either the wood wastes or the refuse. Such schemes are especially attractive as it becomes more and more difficult to dispose of municipal solid waste and forest slash.

The energy plantation concept of designating large areas of relatively low class agriculture land for the production of trees for energy use can be applied to wood fired generation or the production of methanol. Eastern Ontario has been specifically proposed as a suitable location. Fast-growing hybrid poplars could be harvested in two-year or 10-year cycles and fired in a couple of centralized facilities or in several smaller dispersed facilities. Estimates of the amount of generation that could be supplied by 2000 have ranged from 250 MW to about 1,600 MW. The economics of operation, both capital costs and fuel costs, and the vulnerability of trees to disease remain uncertainties; however, the implications are that the economics of biomass-fired stations are similar to those of coal-fired stations, with the added advantage for biomass that is an indigenous renewable resource.

9. The two major options for photovoltaic systems are dispersed generation of several kilowatts on individual rooftops and utility size generation of several megawatts. Due to the intermittent nature of the source, availability will be during the day when there is little cloud cover, and some energy will have to be stored for use during the night and on cloudy days. Thus, the economics will depend on reductions in the cost of both photovoltaic cells and storage batteries. Cell economics will depend on conversion efficiency improvements and the development of mass production techniques. The cadmium sulphide cell, for example, could reach $250/peak kW between 1986 and the year 2000 in the southern U.S. See the paper presented to the Energy Technology VI Conference February 26-8, 1979, by John D. Meakin "Improvement in the Performance of a Low Cost Thin Film Solar Cell". Although costs would be higher in Ontario, it is probable that a demonstration project could be conducted in Ontario before the year 2000.

Notes to Appendix A

1. "Roads to Energy Self-Reliance". Science Council of Canada. Report 30, June 1979.
2. "Oil Sands and Heavy Oils: The Prospects". Energy, Mines and Resources Canada. Report 77-2. 1977.
3. *Ibid.*
4. J.F. Orgill and R.M.R. Higgin, "Component Cost of Solar Energy Systems". Paper presented at Renewable Alternatives Conference of the Solar Energy Society of Canada, August 1978.
5. Ontario Ministry of Energy, "Liquid Fuels in Ontario's Future". Report of the Advisory Group on Synthetic Fuels of the Ministry of Energy, May 1978.